UNITED STATES DEPARTMENT OF THE INTERIOR

FINAL ENVIRONMENTAL IMPACT STATEMENT

VOLUME 2 OF 3

PROPOSED
1978 OUTER CONTINENTAL SHELF
OIL AND GAS LEASE SALE
SOUTH ATLANTIC
OCS SALE NO. 43

APPENDICES

PREPARED BY THE BUREAU OF LAND MANAGEMENT

FINAL

ENVIRONMENTAL IMPACT STATEMENT

PROPOSED

1978

OCS OIL AND GAS LEASE SALE

UNITED STATES DEPARTMENT OF THE INTERIOR

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

BLM
NEW ORLEANS OCS

George L. Turcott
ACTING DIRECTOR

VOLUME 2

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Call For Nominations And Tentative Tract Selection For Proposed South Atlantic OCS Sale No. 43

UNITED STATES DEPARTMENT OF THE INTERIOR

Bureau of Land Management

South Atlantic Outer Continental Shelf

(Tentative Sale No. 43)

Call for Nominations of and Comments on Areas of Oil and Gas Leasing

Pursuant to the authority prescribed in 43 CFR 3301.3 (1974), nominations are hereby requested for areas in the South Atlantic Outer Continental Shelf (OCS) for possible oil and gas leasing under the Outer Continental Shelf Lands Act (43 U.S.C. 1331-1343 (1970)). Nominations will be considered for any or all of the following mapped areas located offshore the States of North Carolina, South Carolina, Georgia, and Florida:

OCS Official Protraction Diagrams

1. **NI 17-9 (Georgetown) - All**
2. **NI 17-12 (James Island) - That portion landward of a line starting at the NE corner of Block 39 running South to the SE corner of Block 655 thence West to the NE corner of Block 686 thence South to the SE corner of Block 994.**
3. **NI 17-11 (Savannah) - All**
4. **NH 17-3 - That portion landward of a line starting at the NE corner of Block 25 running South to the SE corner of Block 597, thence West to the NE corner of Block 622, thence South to the SE corner of Block 974, thence West to the SW corner of Block 969.**
5. **NH 17-2 (Brunswick) - All**
6. **NH 17-5 (Jacksonville) - All**
7. **NH 17-8 (Daytona Beach) - All**
8. **NH 17-11 (Orlando) - That portion landward of a line starting at the NE corner of Block 43 running South to SE corner of Block 527, thence West to the three mile limit.**

These protraction diagrams may be purchased for $2.00 each from the Manager, New Orleans Outer Continental Shelf Office, Bureau of Land Management, Hale Boggs Federal Building, 500 Camp Street, Suite 841, New Orleans, Louisiana 70130. All nominations must be described in accordance with the Outer Continental Shelf Official Protraction Diagrams prepared by the Bureau of Land Management, Department of the Interior and referred to above. Only whole blocks or properly described subdivisions thereof, not less than one quarter of a block, may be nominated. Although individual company nominations are considered to be privileged and confidential information, the names of persons or entities submitting nominations or comments will be of public record.

In addition to requesting nominations of tracts for possible oil and gas leasing within the specified areas, this notice also requests the identification of particular tracts recommended to be either specifically excluded from oil and gas leasing or leased only under special conditions because of conflicting values and environmental concerns. Particular geological, environmental, biological, archaeological, socio-economic or other information which might bear upon potential leasing and development of particular tracts is requested where available. Information on these subjects will be used in the preliminary selection of tracts which precedes any final selection by the Director pursuant to 43 CFR 3301.4. This information is requested from Federal, State and local governments; industry; universities; research institutes; environmental organizations; and members of the general public. Comments may be submitted on blocks or portions thereof, as required for nominations, or on all areas or portions thereof as described above. They should be directed to specific factual matters which bear upon the Department's decision whether to make a preliminary selection of particular tracts within these areas for further environmental analysis pursuant to the National Environmental Policy Act of 1969 (42 U.S.C. 4321-4347 (1970)), and possible leasing. Comments relating to the general matters which would be applicable to oil and gas operations in any part of the OCS are not sought at this time.

Nominations and comments should be submitted not later than November 3, 1975, in envelopes labeled "Nominations of Tracts for Leasing on the Outer Continental Shelf—South Atlantic" or "Comments on Leasing on the Outer Continental Shelf—South Atlantic" as appropriate. They must be submitted to the Director, Bureau of Land Management, Attention: 720, Department of the Interior, Washington, D.C. 20240. Copies must be sent to the Conservation Manager, Geological Survey, Eastern Region, Suite 316, 1825 K Street, N.W., Washington, D.C. 20006 and to the Manager, New Orleans Outer Continental Shelf Office, Bureau of Land Management, at his address cited above.

This call for nominations and comments does not in any way commit the Department to leasing in the South Atlantic. It is an information gathering component of the Department's leasing procedure.

Final selection of tracts for competitive bidding will be made only after compliance with

established Departmental procedures and all requirements of the National Environmental Policy Act of 1969. Notice of any tracts finally selected for competitive bidding will be published in the Federal Register stating the conditions and terms for leasing and the place, date, and hour at which bids will be received and opened.

/s/ CURT BERKLUND
Director, Bureau of Land Management

APPROVED:

/s/ KENT FRIZZELL
Acting Secretary of the Interior

BUREAU OF LAND MANAGEMENT

For Release April 27, 1976, Robinson (202) 343-5717

INTERIOR MAKES TRACT LIST AVAILABLE FOR POSSIBLE OFFSHORE SALE (OCS No. 43) IN SOUTH ATLANTIC

A list of 225 tracts (blocks) totaling 518,400 hectares (1,280,966 acres) has been selected for intensive environmental study for a proposed mid-1977 Outer Continental Shelf oil and gas lease sale (OCS No. 43), the Department of the Interior's Bureau of Land Management announced today.

All of the submerged lands lie in a subsea geologic feature known as the Southeast Georgia Embayment off the coasts of the States of North Carolina, South Carolina, Georgia, and Florida from approximately 48 to 120 km (30 to 74 mi) from the shore in water approximately 13 to 165 m (43 to 541 ft) deep.

Tract selection is the result of evaluation of structure potential by the Department's Geological Survey, of industry nominations of tracts they would like to bid on if a sale is held, and comments from a wide variety of other government and private sources concerning tracts which they believe should not be offered for sale because of environmental or resource use conflicts.

A BLM multidisciplinary team of scientists and other environmental specialists assigned to BLM's New Orleans OCS Office will study the area on a tract by tract basis in preparing a draft environmental impact statement on which public hearings will be held following publication. The hearing record contributes to a final environmental impact statement.

None of these steps constitute an actual decision to hold a sale. They are all part of the series of steps which are required by the Environmental Policy Act of 1969 guidelines issued by the President's Council on Environmental Quality (CEQ), and Department regulations before a decision can be made.

The final statement is submitted to CEQ for 30 days' review, after which the Secretary of the Interior is authorized to decide if there shall be a sale. If he decides to hold a sale, he will also determine how many tracts to offer and what special lease requirements shall be imposed on lessees.

When BLM issued its call for nominations and comments on September 22, 1975, nine petroleum companies nominated 778 tracts totaling 1,792,536 ha (4,429,298 acres) they would like to bid on if a sale is held.

Interior's tentative selection of 225 tracts totaling 518,400 ha (1,280,966 acres) for environmental study does not mean all of these tracts would be offered in the event of a sale. It means that these tracts will be studied intensively to determine if there is sufficient environmental hazard or other resource use conflict reason to rule them out from eventual sale, BLM emphasized.

BLM will seek maximum public input by inviting other Federal, State and local government representatives and many professional groups and private organizations to participate during the preparation of the impact statement.

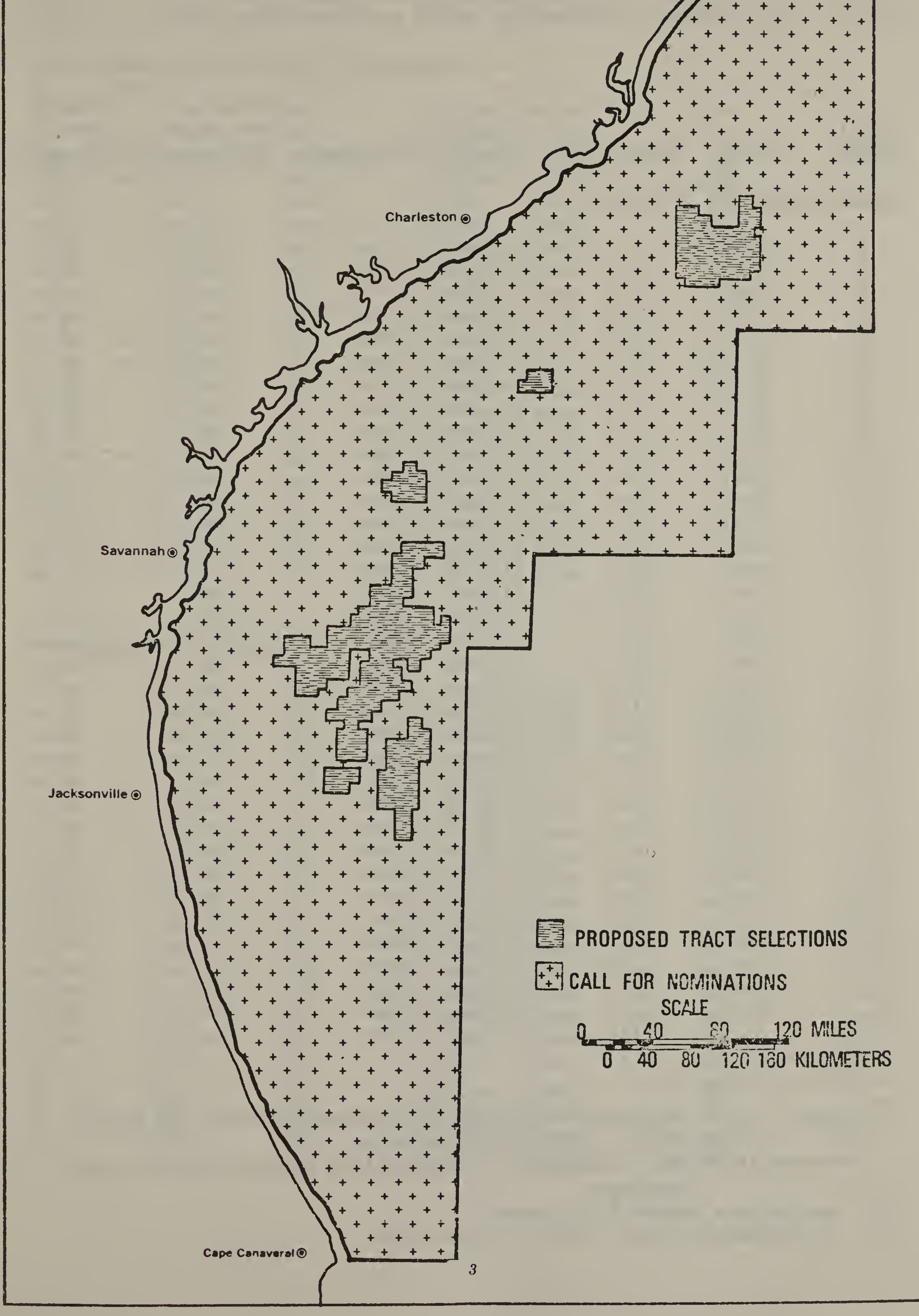
Industry interest was seaward of the coastal areas from Charleston, S.C., to Daytona Beach, Fla. where 13 Federal and State government and private organizations commented that special consideration should be given to environmental concerns or resource use conflicts which were potential impacts of offshore development.

The Southeast Georgia Embayment is in what is termed a frontier OCS area; that is, one in which no offshore development has taken place. The U.S. Geological Survey, an Interior agency, has declared that the frontier areas hold the most promise for finding new OCS oil and gas deposits.

The tentative tract list may be obtained from the Manager, New Orleans OCS Office, BLM, Hale Boggs Federal Building, 500 Camp Street, Suite 841, New Orleans, La. 70130, or from the Director (720) BLM, Washington, D.C. 20240.

A map showing the location of the tracts selected for environmental study is attached.

FIGURE A-1 SOUTHEAST GEORGIA EMBAYMENT FRONTIER OUTER CONTINENTAL SHELF REGION (USDI, 1976).



APPENDIX A

Tract List for Proposed Lease Sale No. 43
(refer to Visuals 1N and 1S for tract locations)

Tract Number	Block	Description	Type/ Reser.1/	Hectares2/	Distance From Shore (Kilometers)3/	Water Depth (Meters)
James Island, NI 17-12 (JI)						
1	115	All	III/O&G	2304	64	36
2	153	All	III/O&G	2304	63	29
3	154	All	III/O&G	2304	68	31
4	159	All	III/O&G	2304	92	36
5	160	All	III/O&G	2304	97	38
6	197	All	III/O&G	2304	48	31
7	198	All	III/O&G	2304	52	33
8	199	All	III/O&G	2304	55	35
9	203	All	III/O&G	2304	68	35
10	204	All	III/O&G	2304	71	36
11	241	All	III/O&G	2304	49	31
12	242	All	III/O&G	2304	55	33
13	243	All	III/O&G	2304	58	35
14	244	All	III/O&G	2304	61	35
15	245	All	III/O&G	2304	64	35
16	246	All	III/O&G	2304	68	35
17	247	All	III/O&G	2304	71	35
18	285	All	III/O&G	2304	55	33
19	286	All	III/O&G	2304	58	33
20	287	All	III/O&G	2304	61	35
21	288	All	III/O&G	2304	64	37
22	289	All	III/O&G	2304	68	38
23	290	All	III/O&G	2304	71	38
24	291	All	III/O&G	2304	74	40
25	292	All	III/O&G	2304	78	46
26	329	All	III/O&G	2304	58	31
27	330	All	III/O&G	2304	61	33
28	331	All	III/O&G	2304	64	38
29	332	All	III/O&G	2304	68	42
30	333	All	III/O&G	2304	71	42
31	334	All	III/O&G	2304	74	42
32	335	All	III/O&G	2304	77	42
33	336	All	III/O&G	2304	80	91
34	373	All	III/O&G	2304	61	38
35	374	All	III/O&G	2304	64	40

1/ Type: III - designates a wildcat tract whose potential for being productive is completely unexplored.
Reservoir: - O&G - designates a tract with a potential oil and gas reservoir

2/ One hectare equals 2.471 acres

3/ One kilometer equals 0.6214 statute mile

Appendix A (continued)

Tract Number	Block	Description	Type/ Reser.	Hectares	Distance From Shore (Kilometers)	Water Depth (Meters)
James Island, NI 17-12 (JI) (continued)						
36	375	All	III/O&G	2304	68	40
37	376	All	III/O&G	2304	71	41
38	377	All	III/O&G	2304	74	43
39	378	All	III/O&G	2304	77	44
40	379	All	III/O&G	2304	80	46
41	380	All	III/O&G	2304	84	91
42	417	All	III/O&G	2304	63	40
43	418	All	III/O&G	2304	71	38
44	419	All	III/O&G	2304	74	40
45	420	All	III/O&G	2304	77	42
46	421	All	III/O&G	2304	80	46
47	422	All	III/O&G	2304	84	55
48	423	All	III/O&G	2304	87	91
49	462	All	III/O&G	2304	70	46
50	463	All	III/O&G	2304	76	45
51	464	All	III/O&G	2304	76	64
52	843	All	III/O&G	2304	69	35
53	844	All	III/O&G	2304	72	40
54	886	All	III/O&G	2304	69	35
55	887	All	III/O&G	2304	76	40
56	888	All	III/O&G	2304	78	42
Brunswick NH 17-2 (Br)						
57	256	All	III/O&G	2304	66	26
58	299	All	III/O&G	2304	60	27
59	300	All	III/O&G	2304	64	27
60	301	All	III/O&G	2304	69	29
61	342	All	III/O&G	2304	57	27
62	343	All	III/O&G	2304	66	27
63	344	All	III/O&G	2304	69	27
64	345	All	III/O&G	2304	72	33
65	387	All	III/O&G	2304	68	27
66	388	All	III/O&G	2304	69	29
67	389	All	III/O&G	2304	71	35
68	608	All	III/O&G	2304	84	40
69	609	All	III/O&G	2304	89	42
70	610	All	III/O&G	2304	92	40
71	611	All	III/O&G	2304	97	40
72	651	All	III/O&G	2304	85	39
73	652	All	III/O&G	2304	89	41
74	653	All	III/O&G	2304	92	43
75	695	All	III/O&G	2304	93	39
76	696	All	III/O&G	2304	97	42
77	739	All	III/O&G	2304	84	40

Appendix A (continued)

Tract Number	Block	Description	Type/ Reser.	Hectares	Distance From Shore (Kilometers)	Water Depth (Meters)
Brunswick NH 17-2 (Br) (continued)						
78	740	All	III/O&G	2304	95	42
79	781	All	III/O&G	2304	85	35
80	782	All	III/O&G	2304	89	36
81	783	All	III/O&G	2304	92	38
82	784	All	III/O&G	2304	95	40
83	825	All	III/O&G	2304	85	33
84	826	All	III/O&G	2304	89	35
85	827	All	III/O&G	2304	92	36
86	868	All	III/O&G	2304	77	29
87	869	All	III/O&G	2304	81	31
88	870	All	III/O&G	2304	86	33
89	871	All	III/O&G	2304	91	35
90	872	All	III/O&G	2304	96	37
91	873	All	III/O&G	2304	103	42
92	874	All	III/O&G	2304	106	44
93	911	All	III/O&G	2304	74	27
94	912	All	III/O&G	2304	78	15
95	913	All	III/O&G	2304	84	16
96	914	All	III/O&G	2304	89	18
97	915	All	III/O&G	2304	92	37
98	916	All	III/O&G	2304	98	22
99	917	All	III/O&G	2304	103	24
100	918	All	III/O&G	2304	108	26
101	920	All	III/O&G	2304	115	46
102	953	All	III/O&G	2304	65	27
103	954	All	III/O&G	2304	70	31
104	955	All	III/O&G	2304	74	15
105	956	All	III/O&G	2304	78	16
106	957	All	III/O&G	2304	84	17
107	958	All	III/O&G	2304	89	19
108	959	All	III/O&G	2304	93	21
109	960	All	III/O&G	2304	98	24
110	961	All	III/O&G	2304	103	24
111	962	All	III/O&G	2304	105	42
112	963	All	III/O&G	2304	110	44
113	964	All	III/O&G	2304	115	46
114	993	All	III/O&G	2304	53	26
115	994	All	III/O&G	2304	58	26
116	997	All	III/O&G	2304	65	27
117	998	All	III/O&G	2304	70	29
118	999	All	III/O&G	2304	75	31
119	1000	All	III/O&G	2304	80	16
120	1001	All	III/O&G	2304	85	18
121	1002	All	III/O&G	2304	74	20
122	1003	All	III/O&G	2304	95	22
123	1004	All	III/O&G	2304	98	23
124	1005	All	III/O&G	2304	103	42
125	1006	All	III/O&G	2304	108	42
126	1007	All	III/O&G	2304	113	44

Appendix A (continued)

Jacksonville NH 17-5 (Ja)

Tract Number	Block	Description	Type/ Reser.	Hectares	Distance From Shore (Kilometers)	Water Depth (Meters)
127	25	All	III/O&G	2304	55	25
128	26	All	III/O&G	2304	60	27
129	27	All	III/O&G	2304	64	29
130	28	All	III/O&G	2304	69	29
131	29	All	III/O&G	2304	74	13
132	30	All	III/O&G	2304	78	15
133	33	All	III/O&G	2304	92	39
134	34	All	III/O&G	2304	97	40
135	35	All	III/O&G	2304	102	40
136	36	All	III/O&G	2304	107	40
137	37	All	III/O&G	2304	112	42
138	38	All	III/O&G	2304	117	42
139	68	All	III/O&G	2304	51	24
140	69	All	III/O&G	2304	55	25
141	70	All	III/O&G	2304	60	29
142	71	All	III/O&G	2304	62	31
143	72	All	III/O&G	2304	67	31
144	73	All	III/O&G	2304	74	15
145	74	All	III/O&G	2304	78	17
146	76	All	III/O&G	2304	87	39
147	77	All	III/O&G	2304	92	39
148	78	All	III/O&G	2304	97	39
149	81	All	III/O&G	2304	110	42
150	114	All	III/O&G	2304	58	29
151	115	All	III/O&G	2304	63	31
152	116	All	III/O&G	2304	68	33
153	117	All	III/O&G	2304	73	33
154	118	All	III/O&G	2304	78	35
155	120	All	III/O&G	2304	88	37
156	121	All	III/O&G	2304	95	39
157	122	All	III/O&G	2304	98	39
158	123	All	III/O&G	2304	102	40
159	158	All	III/O&G	2304	58	26
160	159	All	III/O&G	2304	64	29
161	160	All	III/O&G	2304	68	31
162	164	All	III/O&G	2304	88	36
163	165	All	III/O&G	2304	93	20
164	166	All	III/O&G	2304	97	20
165	167	All	III/O&G	2304	102	22
166	168	All	III/O&G	2304	107	40
167	202	All	III/O&G	2304	60	26
168	203	All	III/O&G	2304	65	27
169	207	All	III/O&G	2304	84	35
170	208	All	III/O&G	2304	88	37
171	209	All	III/O&G	2304	95	20
172	210	All	III/O&G	2304	100	22
173	211	All	III/O&G	2304	105	23

Tract Number	Block	Description	Type/ Reser.	Hectares	Distance From Shore (Kilometers)	Water Depth (Meters)
Jacksonville NH 17-5 (Ja) (continued)						
174	250	All	III/O&G	2304	82	35
175	251	All	III/O&G	2304	86	35
176	252	All	III/O&G	2304	95	36
177	253	All	III/O&G	2304	98	40
178	293	All	III/O&G	2304	77	33
179	294	All	III/O&G	2304	82	35
180	295	All	III/O&G	2304	87	35
181	296	All	III/O&G	2304	92	37
182	339	All	III/O&G	2304	86	37
183	345	All	III/O&G	2304	115	44
184	382	All	III/O&G	2304	81	35
185	383	All	III/O&G	2304	86	35
186	384	All	III/O&G	2304	91	37
187	389	All	III/O&G	2304	115	46
188	390	All	III/O&G	2304	120	64
189	426	All	III/O&G	2304	81	33
190	427	All	III/O&G	2304	86	35
191	428	All	III/O&G	2304	91	37
192	431	All	III/O&G	2304	104	42
193	432	All	III/O&G	2304	109	44
194	433	All	III/O&G	2304	114	55
195	434	All	III/O&G	2304	119	91
196	470	All	III/O&G	2304	80	35
197	471	All	III/O&G	2304	85	35
198	472	All	III/O&G	2304	90	37
199	475	All	III/O&G	2304	103	42
200	476	All	III/O&G	2304	108	44
201	477	All	III/O&G	2304	113	55
202	478	All	III/O&G	2304	118	101
203	519	All	III/O&G	2304	105	44
204	520	All	III/O&G	2304	110	46
205	521	All	III/O&G	2304	115	64
206	557	All	III/O&G	2304	75	35
207	558	All	III/O&G	2304	80	35
208	559	All	III/O&G	2304	85	37
209	562	All	III/O&G	2304	98	40
210	563	All	III/O&G	2304	105	44
211	564	All	III/O&G	2304	108	53
212	565	All	III/O&G	2304	114	91
213	601	All	III/O&G	2304	74	35
214	602	All	III/O&G	2304	79	35
215	606	All	III/O&G	2304	98	40
216	607	All	III/O&G	2304	101	46
217	608	All	III/O&G	2304	108	55
218	609	All	III/O&G	2304	111	91
219	650	All	III/O&G	2304	98	42

Appendix A (continued)

Tract Number	Block	Description	Type/ Reser.	Hectares	Distance From Shore (Kilometers)	Water Depth (Meters)
Jacksonville NH 17-5 (Ja) (continued)						
220	651	All	III/O&G	2304	101	46
221	652	All	III/O&G	2304	108	55
222	653	All	III/O&G	2304	110	165
223	696	All	III/O&G	2304	104	82
224	740	All	III/O&G	2304	103	91
225	784	All	III/O&G	2304	102	110

Appendix B

Report On Estimates For The Proposed South Atlantic OCS Sale No. 43

UNITED STATES DEPARTMENT OF THE INTERIOR

Geological Survey

Reston, Virginia 22092

July 2, 1976
Memorandum
TO: Director, Bureau of Land Management
THROUGH: Deputy Assistant Secretary—Energy and Minerals; Deputy Assistant Secretary—Land and Water Resources
FROM: Acting Director—Geological Survey
SUBJECT: Request for estimates and information for proposed OCS Lease Sale No. 43, South Atlantic

Enclosed for your information is our reply to the subject request. It should be pointed out that estimates of resource potential are inherently speculative and particularly so in areas where geological information is limited and the presence of oil and gas has not been demonstrated. It should also be emphasized that the operational projections and estimates are highly speculative and represent a possible development scheme based on many variables and assumptions.

It will be noted that certain requests relating to employment impacts, locations of transportation facilities, and magnitudes of support related industry impacts were not addressed in the enclosed report. At this stage of planning, comments on these subjects were felt inappropriate. Furthermore, since the material requested by items 7 and 8 have been previously furnished to BLM, New Orleans, in the summary report, they were also deleted from the enclosed report.

/S/ HENRY W. COULTER
Acting Director

ENCLOSURE

REPORT ON ESTIMATES FOR THE PROPOSED SOUTH ATLANTIC OCS SALE NO. 43

Amounts of Recoverable Resources (Range and Mean)

In making this forecast, the proposed sale tracts were identified as those tentatively selected by GS and BLM on the Southeast Georgia Embayment and publicly announced on April 27, 1976. The 225 tracts announced constitute approximately 1,280,966 acres (518,400 hectares). Figure 1 illustrates tract locations.

The method chosen for estimating recoverable resources in the selected frontier area tracts is based on a volumetric concept and utilizing proprietary geophysical data. First, from available seismic mapping, it can be calculated that the proposed sale tracts contain an area of closure of about 403,456 acres. This area of closure considered geologic interpretations of structural and stratigraphic traps, as well as possible sub-basement prospects. Next, assuming that only 20 percent of the structural area identified will contain hydrocarbon and that a 50 percent fill-up exists on these entrapment features, it can be calculated that only 40,346 acres would be productive. Finally, it was assumed that recovery factors would range from a low of 7,000 barrels per acre (based on certain Gulf Coast fields of similar age) to a high of 25,000 barrels per acre (based on an average of giant Mesozoic fields in the U.S.). The resultant recoverable resource estimates therefore are as follows:

	Low	*High*	*Mean*
Oil (Billions of barrels).........	0.282	1.009	0.65
Gas (Trillions of cubic feet)...	1.890	6.810	4.30

The assumptions on the range of recovery factors and the portions of structures that could be hydrocarbon productive involve subjective judgments. Considering the high degree of uncertainty associated with these variables, collectively, it is cautioned that a zero lower limit for resource estimates does exist. Secondly, since the sale tracts were for the most part selected on the basis of their favorable geologic setting, and since the regional statistical analysis procedures for resource estimates are not directly comparable to the above tract specific estimates, probabilities for the above values, including a zero estimate, should not be assigned. The above estimates were developed principally to assist socio-economic impact scenarios specifically related to OCS Sale No. 43.

WELLS AND DRILLING SCHEDULE

The number of wells and predicted work schedules of exploratory wells, development wells, exploratory rigs and development platforms that might be associated with a search for the volume of resource described above is summarized (yearly) in two scenarios. Table I presents a scenario based on the low end of the range of the resource estimates. Table II presents a scenario based on the high end of the range.

Certain of the assumptions used for construction of Tables I and II are shown as footnotes.

OIL AND GAS PRODUCTION RATES — LOW RESOURCE SCENARIO

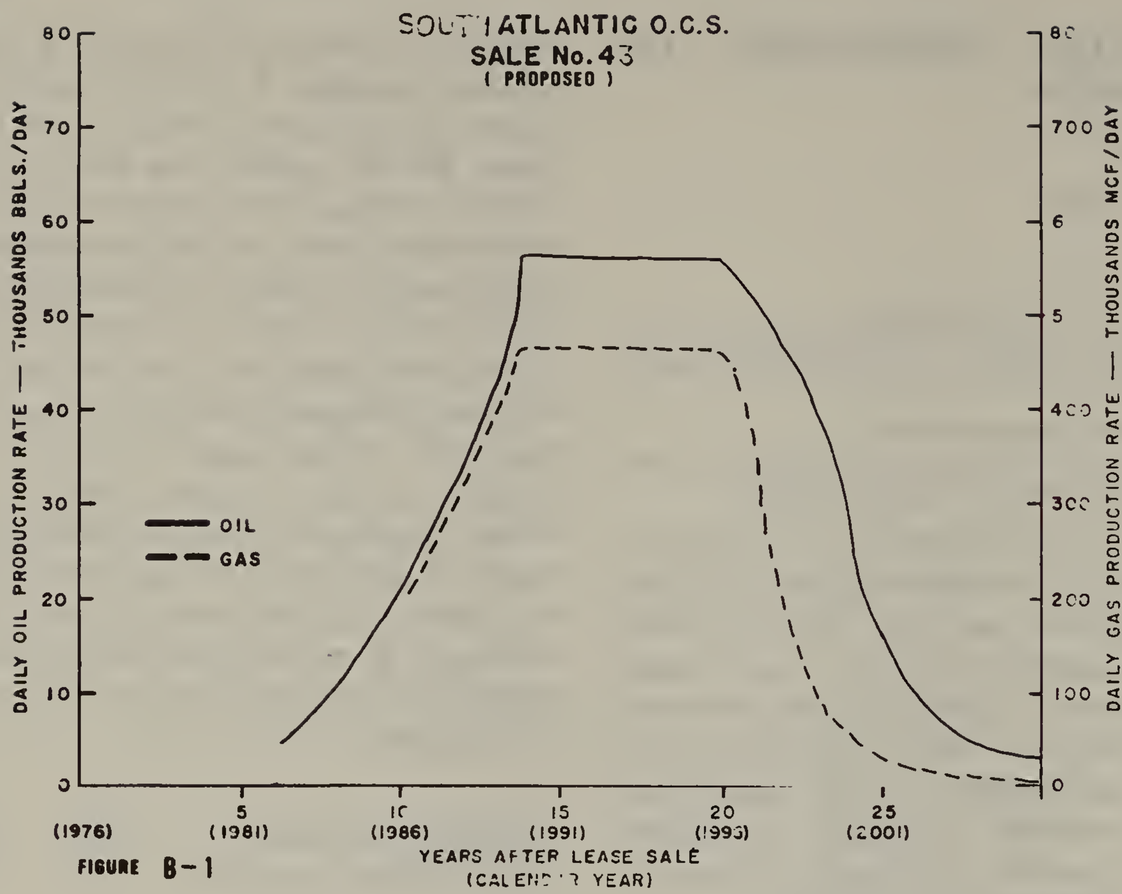


FIGURE B-1

OIL AND GAS PRODUCTION RATES — HIGH RESOURCE SCENARIO

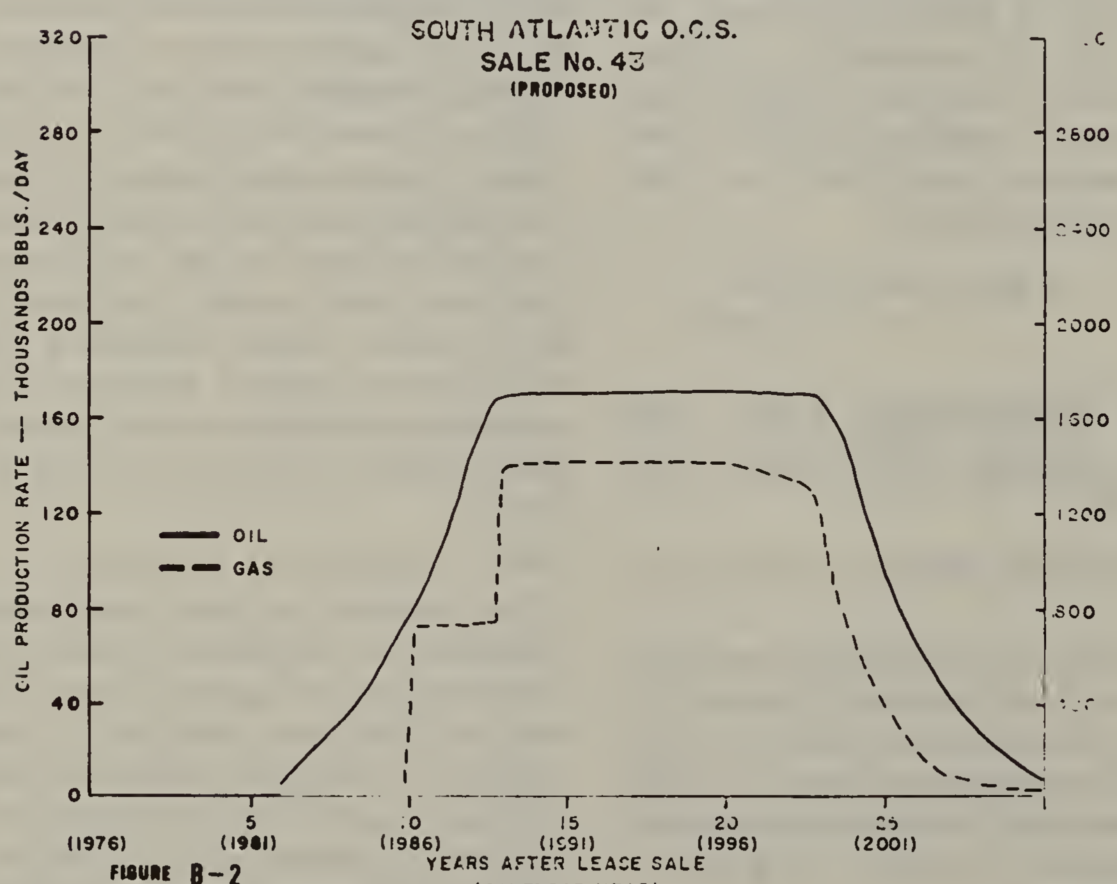


FIGURE B-2

Table 1

SOUTH ATLANTIC OCS SALE #43
Low Recoverable Resource Scenario
Schedule of Exploration, Development and Production

Year	Explor. Rigs/Wells Drilled	Platforms and Equip. Installed (Producing)	Dev. Wells Drilled (Producing O/G)	Large Diam. Oil Pipelines (Offshore Miles)	Onshore Terminals	Annual Production Quantity Sold Oil MM Bbls.	Annual Production Quantity Sold Gas MMMCF
1976	(Proposed OCS Sale #43 - as scheduled - Nov. '76 or later)						
77	4/12						
78	5/15						
79	5/15						
80	3/9						
81	3/9	1	5				
82	2/5	1 (1)	15 (4/0)			1.1	0
83	2/5	2 (3)	25 (11/0)			2.5	0
84	2/5	2 (5)	40 (19/0)			4.0	0
85	2/5	2 (7)	30 (30/0)	1 (80)-oil	1	5.8	0
86	1/3	1 (8)	20 (45/7)	1 (80)-gas		8.4	73
87	1/3	1 (9)	20 (60/10)			10.9	100
88	1/3	(10)	5 (74/12)			13.5	125
89	1/3	(10)	(92/15)			16.4	154
90	1/3	(10)	(110/18)			20.6	170
91		(10)	(110/18)			20.6	170
92		(10)	(110/18)			20.6	170
93		(10)	(110/18)			20.6	170
94		(10)	(110/18)			20.6	170
95		(10)	(110/18)			20.6	170
96		(10)	(110/18)			20.6	170
97		(10)	(108/18)			18.6	110
98		(10)	(105/17)			16.4	66
99		(10)	(105/17)			14.6	30
2000		(8)	(70/10)			9.1	15
01		(7)	(58/8)			6.6	10
02		(3)	(37/7)			3.7	4
03		(2)	(26/4)			2.2	4
04		(2)	(26/4)			1.8	3
05		(1)	(17/3)			1.1	3
06		(1)	(16/2)			1.1	3
Totals	95	10	160	2 (160)	1	282	1,890

* Footnotes on separate page

Table 11

SOUTH ATLANTIC OCS SALE #43
High Recoverable Resource Scenario
Schedule of Exploration, Development and Production

Year	Explor. Rigs/Wells Drilled	Platforms and Equip. Installed (Producing-O/G)	Dev. Wells Drilled (Producing	Large Diam. Pipelines (Offshore Miles)	Onshore Terminals	Annual Production Quantity Sold Oil MM bbls.	Annual Production Quantity Sold Gas MMMCF
1976	(Proposed OCS Sale #43 - as scheduled - Nov. '76 or later)						
77	4/12						
78	10/30						
79	10/30						
80	10/30						
81	7/21	2	10				
82	5/15	2 (2)	25 (10/0)			3	0
83	5/15	3 (4)	50 (32/0)			9	0
84	5/15	3 (6)	70 (53/0)			15	0
85	5/15	3 (8)	75 (75/0)	1 (80)-oil	1	20	0
86	3/9	3 (13)	60 (108/18)	1 (80)-gas		28	256
87	3/9	3 (16)	60 (146/24)			36	265
88	3/9	3 (19)	60 (214/36)	1 (80)-oil	1	49	265
89	1/3	3 (21)	40 (275/46)	1 (80)-gas		59	496
90	1/3	(23)	25 (300/56)			61	510
91	1/2	(25)	20 (326/57)			62	510
92	1/2	(25)	5 (343/57)			62	510
93		(25)	(343/57)			62	510
94		(25)	(343/57)			62	510
95		(25)	(343/57)			62	510
96		(25)	(343/57)			62	502
97		(25)	(343/57)			62	493
98		(25)	(343/54)			62	493
99		(25)	(343/50)			61	470
2000		(23)	(300/45)			55	270
01		(23)	(257/26)			45	160
02		(20)	(154/23)			26	47
03		(18)	(137/15)			19	15
04		(15)	(95/10)			14	7
05		(12)	(62/8)			7	7
06		(10)	(52/3)			5	4
07		(4)	(17/0)			1	0
Totals	220	25	500	4 (320)	2	1,009	6,810

* Footnotes on separate page

Footnotes for Table 1 and 11.

1. Assumed 4 to 12 exploratory drilling rigs will be initially working in the sale area.

2. Drilling rate of exploratory rigs will be 2 to 4 wells/yr.

3. Convention platforms (normally) will be installed.

4. The development wells drilled for each platform will range from 10 to 20.

5. The success rate for development drilling will be 80%.

6. Development platforms will use 1 or 2 rigs each.

7. Development drilling on platforms will be 5 wells/per rig/year.

Investments/Costs

The following are estimates (only) of the expenditures associated with the low and the high exploration and development scenarios presented above.

Production costs per barrel:

For the purposes of this forecast, the oil will be valued at \$11.00 per barrel and gas at \$1.00 per MCF.

Gross value of oil and gas will range from \$5.0 to \$17.9 Billions

(low case) (282,000,000 bbls. of recoverable oil x \$11.00)
+(1,890,000,000 MCF of recoverable gas x \$1.00) =
\$4,992 Millions

(high case) (1,009,000,000 bbls. of recoverable oil x \$11.00)
+(6,810,000,000 MCF of recoverable gas x \$1.00) =
\$17,909 Millions

Average Annual Royalties for oil and gas will range from \$35.7 to 125.1 Millions

(low case) oil @ 11,280,000 bbls/yr x 1/6 x \$11.00 = \$20.7 Millions
+ gas @ 90,000,000 MCF/yr x 1/6 x \$1.00 = \$15.0 Millions
\$35.7 Millions

(high case) oil @ 38,800,000 bbls/yr x 1/6 x \$11.00 = \$71.1 Millions
+ gas @ 324,300,000 MCF/yr x 1/6 x \$1.00 = \$54.0 Millions
\$125.1 Millions

Average Annual Operating Costs will range from \$63.7 to \$236.0 Millions

	(low case)	(high case)
Royalty	\$33.3 (Millions)	119.4 (Millions)
Labor	3.0	15.0
Transportation (Personnel & Cargo)	6.0	20.4
Workover	3.0	15.0
Well Servicing	6.0	20.0
Equipment Maintenance	5.0	17.2
Overhead	1.0	6.0
Transportation (oil and gas)	3.4	12.0
Misc.	3.0	11.0
Total	\$63.7 Millions	\$236.0 Millions

Assuming that operating costs for oil and gas are proportional to their gross value:

- average annual operating cost for oil should be about - $3.64 /Bbl.

(low case) $\frac{3.10}{4.99}$ x \$ 63.7 Millions = \$ 39,573,000

$\frac{\$\ 39{,}573{,}000/\text{yr}}{11{,}280{,}000\ \text{bbls/yr}}$ = \$ 3.50

(high case) $\frac{11.10}{17.91}$ x \$ 236.0 Millions = \$ 146,264,000

$\frac{\$\ 146{,}265{,}000/\text{yr}}{38{,}800{,}000\ \text{bbls/yr}}$ = \$ 3.77

- average annual operating cost for gas should be about - $ .28/MCF

(low case) $\frac{1.89}{4.99}$ x \$ 63.7 Millions = \$ 24,127,000

$\frac{\$\ 24{,}127{,}000/\text{yr}}{90{,}000{,}000\ \text{MCF/yr}}$ = \$ .27/MCF

(high case) $\frac{6.81}{17.91}$ x \$ 236.0 Millions = \$ 89,735,000

$\frac{\$\ 89{,}735{,}000/\text{yr}}{324{,}300{,}000\ \text{MCF/yr}}$ = \$ .28/MCF

Major Capital Investments are also shown as a range based on the low and the high development scenarios.

	Low Case $ Millions		High Case $ Millions	
High bonus bids @ $1250/acre for 130 tracts	930		930	
Exploration wells @ $2.0 million	190	(95)	440	(220)
Platforms w/prod. equipment @ $25 million	250	(10)	625	(25)
Development wells @ $0.5 million	80	(160)	250	(500)
Miles of oil pipelines @ $1/million/mi	80	(1)	160	(2)
Miles of gas pipeline @ $1/million/mi	80	(1)	160	(2)
Onshore oil terminals @ $250 million	250	(1)	500	(2)
Onshore gas processing @ $400 million	400	(1)	800	(2)
Pollution containment	50		50	

Total Capital Exp. $2,310 Millions to $3,915 Millions

In summary, capital investment could be expected to range from $2.3 to $3.9 Billions. Probably the most uncertain category are those items associated with transportation.

Comparisons with OCS development areas, principally the Gulf of Mexico, represents the basis for these assumptions.

The depth of wells for the proposed sale area is estimated to range from 5,000 feet to 15,000 feed below the seafloor. An average depth might be 10,000 feet. These assumptions on well depths are based on the expected depth ranges of targets within Cretaceous and Jurassic age Mesozoic sediments.

Platforms

Because of the water depth (50 to 330 feet), the expected number of small structures, and the modest resource estimates, the majority of platforms will probably be of the conventional type. Use of gravity structures seems unlikely. In areas which may be sensitive to heavy bottom loading, it is conceivable that underwater well completions and subsea or floating production systems may also be used. The number of platforms could be forecast to range from 10 to 25, based on the development schedules enclosed.

Production Schedule

A yearly production schedule based on the above resource and drilling forecast data is also shown on Tables I and II for the low and the high scenarios, respectively. Peak production rates are expected to be reached 12 to 14 years after the sale date and are forecast to achieve levels of from about 56,000 BOPD and 466,000 MCFPD to about 170,000 BPOD and 1,400,000 MCFPD. Graphs of the daily production rates for the low and the high scenarios are attached as Figures 2 and 3, respectively.

Muds, Drill Cuttings and Brines

From 230 tons to 1,000 tons of commercial drilling mud components will be used in each well, depending upon depth. This range of material is given for a 10,000 ft. to 15,000 ft. well. An estimate of the ratio of water base drilling fluid to oil base drilling fluids could range from 30:1 to 50:1 based on the projected number of wells and reservoirs.

It can be estimated that 682 tons (9,460 cu. ft.) to 1,079 tons (15,000 cu. ft.) of formation cuttings will result from drilling each 10,000 ft. to 15,000 ft. well.

Initial production will be low in water volume, but throughout a 25-year production life, it can be estimated that the ratio of the total barrels of produced salt water to the total barrels of produced crude oil will be 1:1.

Transportation/Storage/Refining

Transportation of the predicted production under both of the scenarios discussed above will be treated as the one question. Due to the modest production rates forecast, transportation facilities would seem to indicate no significant onshore impact. The variations in possible transportation scenarios would likewise be limited.

It can be anticipated that, due to the dispersion of tract locations in proposed sale area, their distance from shore, and the anticipated small pool sizes, initially transportation of oil would be via tankers. Tankers would probably be of the 16,000 to 25,000 dwt class. Furthermore, unless or until strategically convenient deliverability of about 70,000 BOPD, the construction of an oil pipeline to shore is doubtful. Based on this empirical rule of thumb, no more than 3 oil pipelines can be predicted to result from the subject sale. However, until after the sale when the leased tract locations and distribution become available, and because of the low resources anticipated, it is difficult to firmly predict that more than two oil pipelines will be constructed.

The initial dependence on tanker transport is foreseen for 3 to 5 years after production is commenced. This time frame of course is subject to the timing and quantity of resource discoveries. Therefore, in the period 1978–84, and investment decision can be anticipated on whether or not to construct an oil pipeline to shore.

As to the positioning and land fall for pipelines, it appears too conjectural to predict at this time.

Assuming no new southeastern refinery is constructed, crude oil brought ashore in tankers or in pipelines would have to be processed at existing facilities. The intercoastal tanker linkage of the South and Mid-Atlantic areas is also a possible consideration.

Until a pipeline to transport associated and nonassociated gas is installed, the majority of the produced gas would be injected into oil reservoirs. Using the empirical rule that a gas pipeline will be installed for each 700,000 MCFPD of deliverability, it is estimated that 1 or 2 gas pipelines will be installed. A minor amount of gas flaring on a temporary basis can also be anticipated.

Probably not more than 2 gas processing plants will be constructed to provide for the handling of produced gas. They would be located in the coastal areas adjacent to discoveries and have a capacity of 300,000 to 500,000 MCFPD.

If logistics and environmental conditions permit, it is conceivable that both oil and gas pipelines will utilize the same corridor to shore. Under environmental safeguards, pipelines will probably be buried from shore out to 200 feet of water depth and wherever they would represent a hazard to multiple use of the sea floor. From 3,000 to 8,000 cu. yds. of sediment are estimated to be disturbed for each mile of buried pipeline. Onshore distances and volume of disturbance are too speculative to estimate.

Whether or not oil pipelines are determined to be economically feasible, the dispersion of selected tracts seems to indicate that transportation scenarios should include some offshore storage in conjunction with tankering. Crude storage would probably initially be on surface with the later consideration of permanent subsea storage tank(s) awaiting the decision on a pipeline. Single-moored buoy loading facilities for tankers might also be expected.

No refinery is expected to be constructed in South Atlantic as a result of this sale. The refinery question appears to be mutually exclusive of the sale. The investment forecast discussed below, therefore, does not include such a contingency.

Appendix C

Oil and Gas Operations

DESCRIPTION OF OFFSHORE OPERATIONS EXPECTED IN THE SOUTH ATLANTIC OCS

Exploration

Before drilling commences on any tracts that may be leased in this proposed South Atlantic sale area, additional geophysical studies may be conducted (after obtaining permission of the United States Geological Survey) in order to further define the location of prospects, design the drilling mud program and coring strategies, and choose the safest drilling sites.

In seismic exploration, a ship travels along a predetermined path, towing signal generating and recording equipment. The signal generated by the energy source is a series of small amplitude seismic pulses that travel at the speed of sound through the water and sediment below, where they are reflected and refracted by the underlying strata. An array of sensitive detectors towed by the vessel receive incoming seismic waves which are then recorded on magnetic tape. After extensive computer processing, the recordings are displayed in the form of vertical cross-sections. The seismic profiles are then interpreted to identify the location, size and shape of geologic structures favorable to oil and gas accumulation. This information is normally displayed as a series of subsurface seismic contour maps.

It is assumed that the generation of signals will be by sources other than dynamite since these modern devices, which include sparkers, air guns and gas guns have become widely accepted and account for over 95% of marine seismic energy sources currently in use.

Industry officials anticipate that drilling rigs will be brought up from the Gulf of Mexico and that jack-ups, semi-submersibles, and drillships will be used.

The bottom supported rigs (jack-ups) are floated from one location to another, and are most vulnerable to damage or loss while in transit. Shallow (less than 350 feet or 100 meters) water exploratory drilling is commonly carried out using a ''jack-up'' type drilling rig (see Figure 1) while deeper waters require the use of semi-submersible rigs or drillships. The jack-up rig is towed into position and the legs jacked downward to contact the bottom and lift the platform nine to 15 meters above the water surface.

Semi-submersibles are large, advanced-design floating rigs that have better motion characteristics in rough seas than do ships or barges (see Figure 1). These rigs are floated to the site, partially submerged and held in place by anchors. These units can work in water depths up to 300 meters and beyond. The semi-submersibles as well as drillships, if used, would be connected to seafloor equipment by buoyant riser pipes.

Winds, waves and ocean currents tend to push floating drill platforms off location regardless of how good the mooring system. This can put excessive stresses on a riser. One company uses an acoustic position reference system whereby acoustic signals from a beacon located near the wellhead on the seafloor are received by three shipboard hydrophones (see Figure 2). In use, the vessel's position is determined by comparing, at each of the three shipboard hydrophones, the signal either emitted by or reflected from the seafloor beacon. The correct position, with reference to the wellbore, is shown on the shipboard console viewing screen and the vessel kept in position by adjusting mooring lines or using the ship's engines plus special horizontal thruster engines. If, for some reason, the drillship should have to move off location, the seafloor beacon or reflector is used to reposition the vessel upon return.

Once the drilling rig is in place, the drive pipe, blowout preventers and riser are installed. Drilling then commences with drilling mud circulating through the wellbore to provide pressure control, lubrication of the drill bit, and circulation of wellbore cuttings out of the hole.

In spite of considerable research, it is still not always possible to predetermine, for wildcat wells, the formation pressure and the fracture pressure that the wellbore will encounter. During drilling there are several means of determining the trend in pressure. They include measurements such as formation temperature (as evidenced by the temperature of the returning mud), shale density and changes in the penetration rate of the drill bit.

If the hydrostatic gradient of the drilling fluid may enter the wellbore from the formation being drilled, the influx displaces some drilling fluid, thereby causing reduction in the hydrostatic head in the annular space between the drillpipe and the borehole (Figure 3).

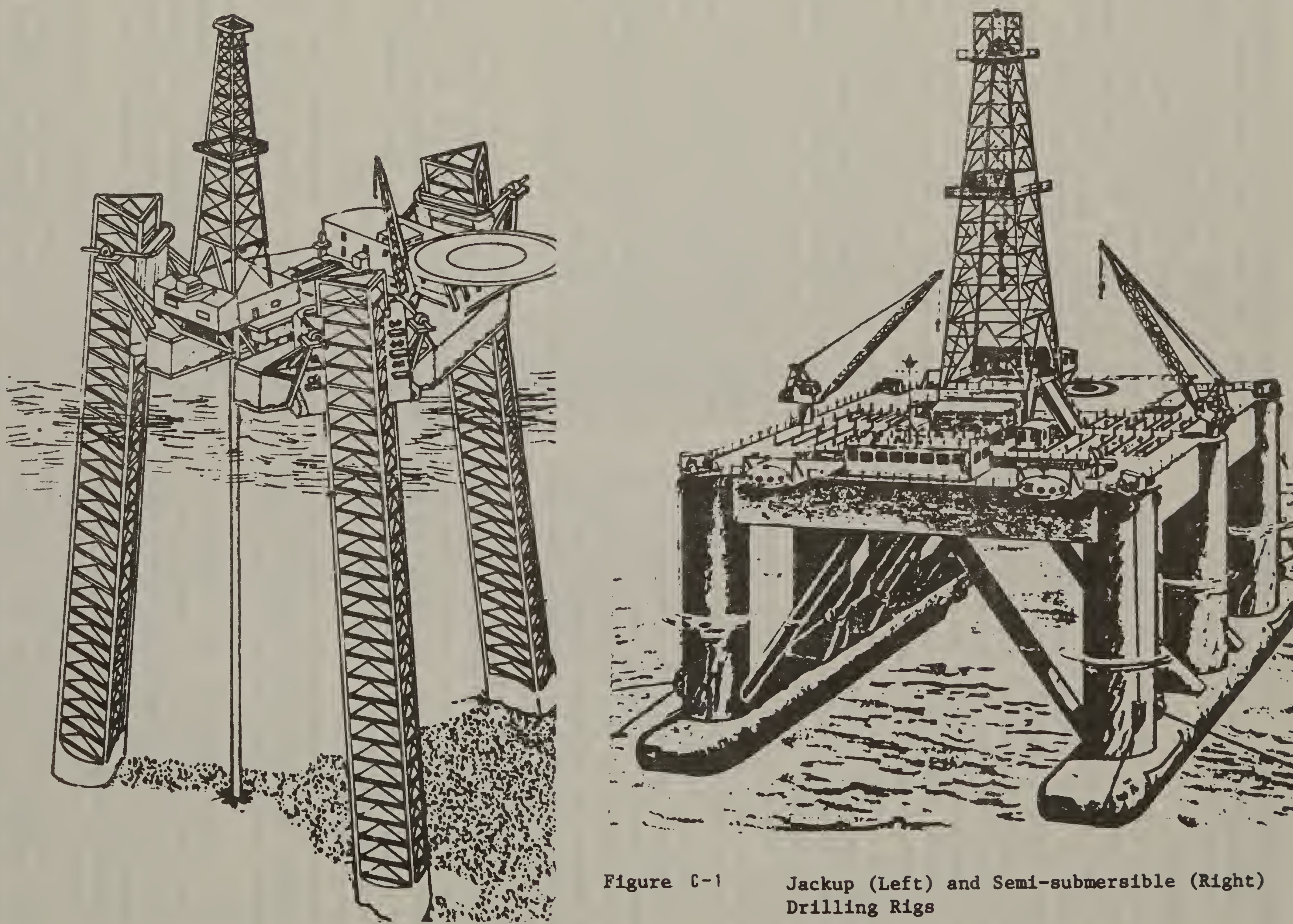


Figure C-1 Jackup (Left) and Semi-submersible (Right) Drilling Rigs

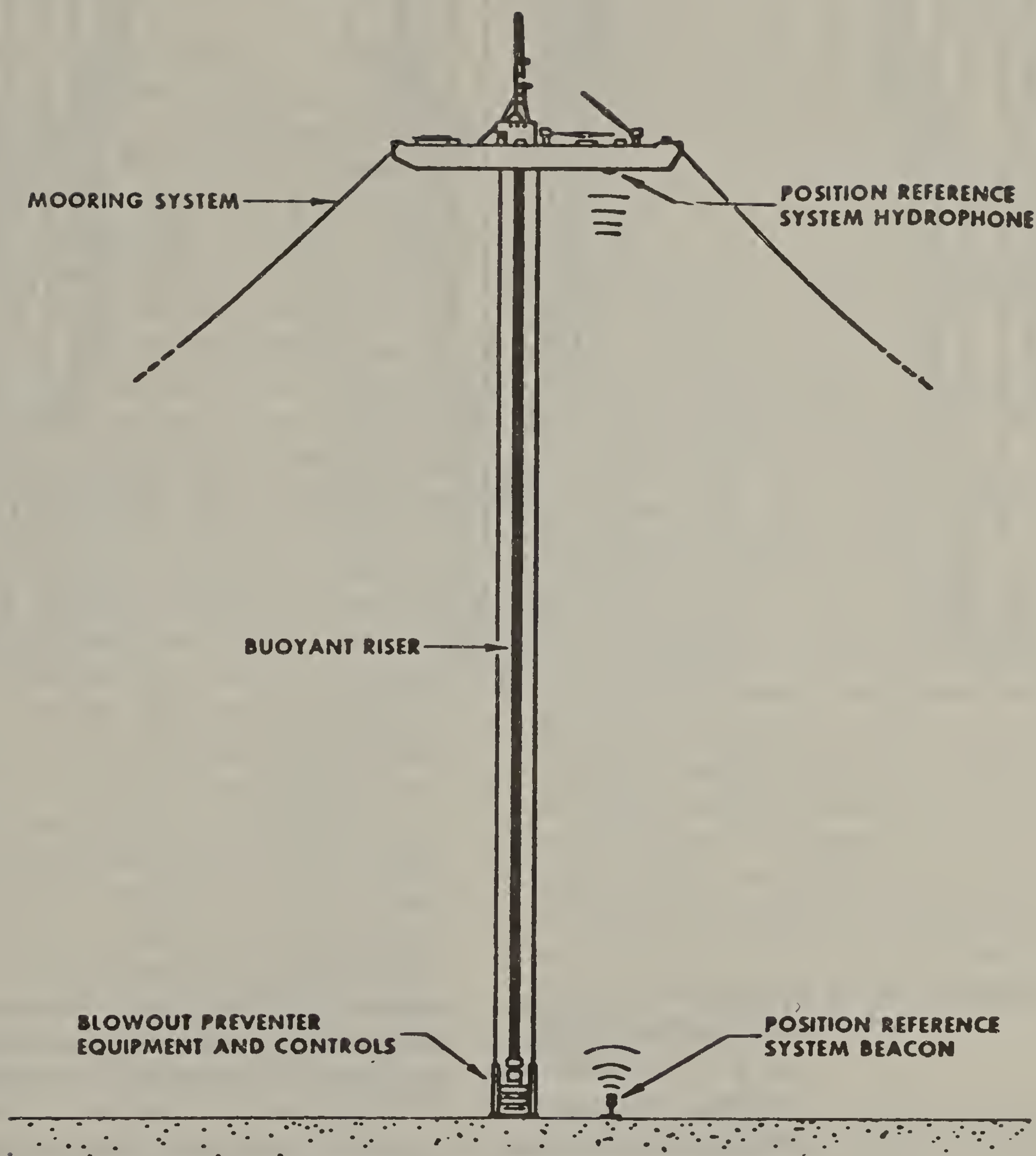


Figure C-2 Drill Ship Operations

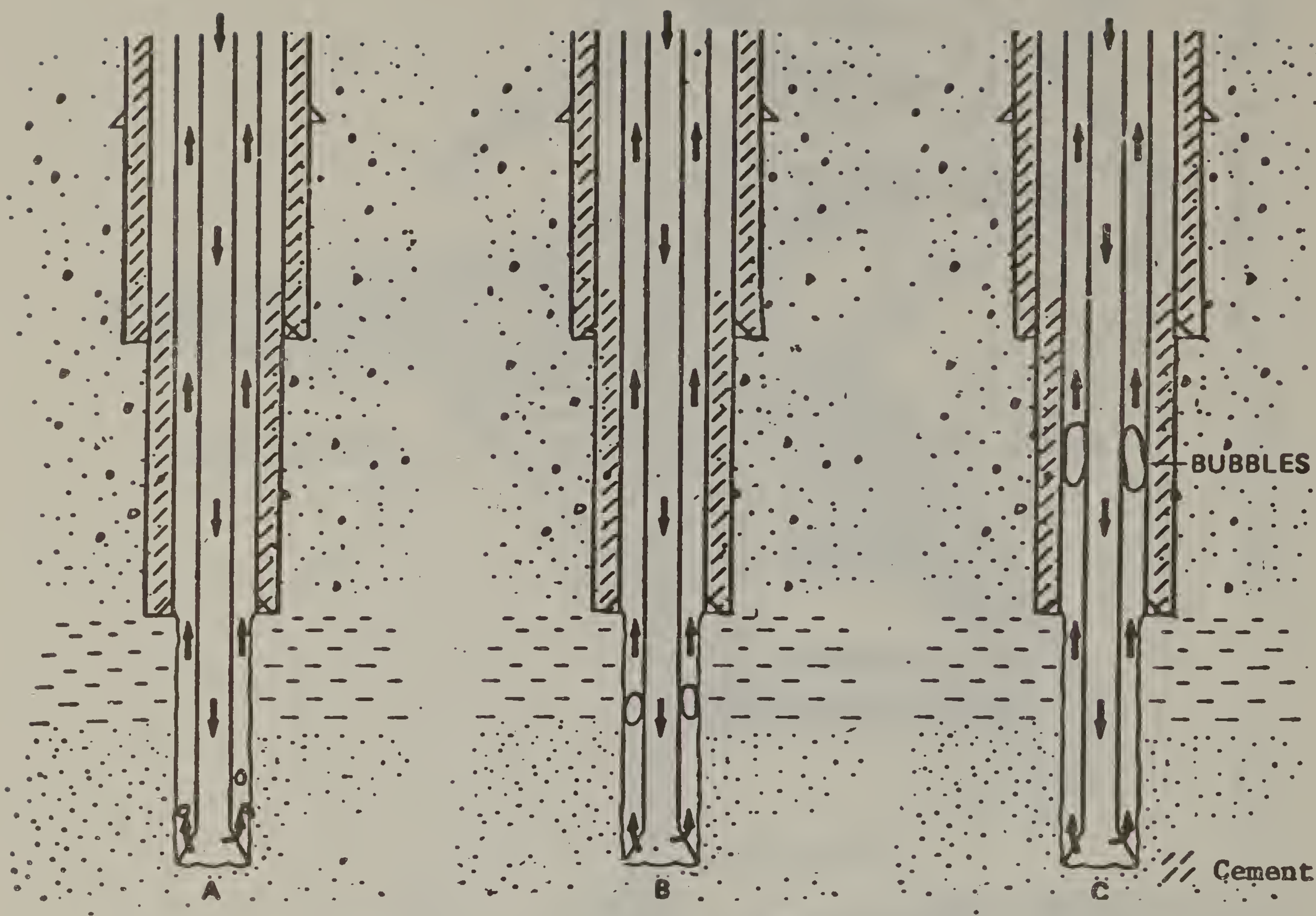


Figure C-3 A "kick" is a gas or liquid influx that reduces the hydrostatic head in the annulus. Here, the kick is a gas bubble (A). As it rises (B and C), it expands causing a sudden increase in the upflow of the mud. When the bubble reaches the top, if it has not been allowed to expand, the bottom-hole pressure reaches a maximum--the sum of mud pressure and gas pressure. This pressure maximum, if excessive, can exceed the formation fracture pressure, and lead to a loss of drilling mud to the formation, thus further decreasing the hydrostatic pressure. This could cause an influx of formation fluids into other formations, or the fractured formation taking fluid from another formation, commonly referred to as an underground blowout.

If the volume of the influx is not excessive, and a surface indication (increased mud tank volume) is observed in time, the unwanted influx of fluid or gas can be circulated and adherence to preplanned emergency procedures. From the record of a kick, the bottom-hole pressure can be determined and with this pressure known, the mud weight can be adjusted to provide the correct hydrostatic head for the safe continuation of drilling.

An uncontrolled kick is called a "blowout". Blowouts seldom occur and usually can be controlled by implementation of preplanned emergency procedures and actuation of devices known as "blowout preventers" which are mounted on every offshore well during drilling. Actual blowout preventers used offshore are of at least three types; a bag-type, one with blind rams, and one with pipe rams. Blowout preventers are essentially large valves that can close around the drill string or across an open hole and seal off the well at the surface. These valves are so powerful that some are equipped with shear rams that can cut the drill pipe should this procedure aid in controlling the well. The blowout preventer stack can also be mounted on the sea floor and remotely controlled at the drilling console. These sea floor BOP stacks are designed to be used in any water depth and have reaction times of 10 seconds or less. Blowouts can occur downhole when a low-pressure formation fractures, and fluids from a higher-pressure zone flow into the fractured formation. Such underground blowouts, like surface blowouts, require the careful use of preplanned emergency techniques to regain control. Blowout preventers and other well-control equipment must meet the requirements of OCS Orders. This equipment is tested on a schedule set by prudent practice, but not less often than regulations specify.

To ensure that adequate provisions have been made for safety and well control, the casing program and drilling fluid, or mud program must be approved by the Geological Survey before a drilling permit is issued. Along with adequate casing, it is important that enough cement be spotted between the casing and the wall of the hole to seal off and isolate all sensitive geological formations such as hydrocarbon zones and freshwater sands, and to separate zones of abnormal pressure from those with normal pressures. Mud components are described in Chapter III.A.

Should the initial test be dry, an exploratory well is usually plugged and abandoned. Cement plugs are set to confine formation fluids in their parent subsurface formations, to prevent them from intermingling, and to prevent flow to the surface. During plugging operations, well-control equipment remains in use. When a well is abandoned, the casing is cut off below the mud line, all obstructions are removed, and the bottom is dragged to be sure that no obstructions were overlooked. In some cases, it may be necessary to drill several exploratory wells on each block before a lease is totally condemned.

If well tests show that commercial quantities of natural gas or oil have been found, it may be necessary to drill several additional confirmation tests before the company is satisfied that the reserves will support a development drilling and well completion program. If petroleum deposits prove to be commercial in quantity, one of two courses of action may be followed:

(1) The exploratory well may be deemed expendable and be permanently abandoned. Procedures followed would be the same as above for a dry-hole abandonment.

(2) The well may be deemed useful as a future production well and temporarily abandoned. In this case, a mechanical bridge plug is placed in the smallest string of casing and the well head capped and left for future entry when production activity commences. This results in the temporary existence of an underwater "stub". The Coast Guard District Commander requires that such stubs be marked by a buoy at the surface if located in 60 meters of water or less, and that the buoy be lighted if located in 26 meters of water or less.

Development

Offshore drilling and production operations are usually conducted on fixed, bottom-founded, water surface-piercing platforms. If exploratory efforts are successful in proving a hydrocarbon reserve, production operations are initiated by installing platforms (Figure 4) to serve as a base for drilling development wells and for subsequent producing operations. A number of wells may be directionally drilled to develop a large area from a single platform.

During the history of OCS oil operations around the world, industry has gained a good understanding of the physical forces acting on

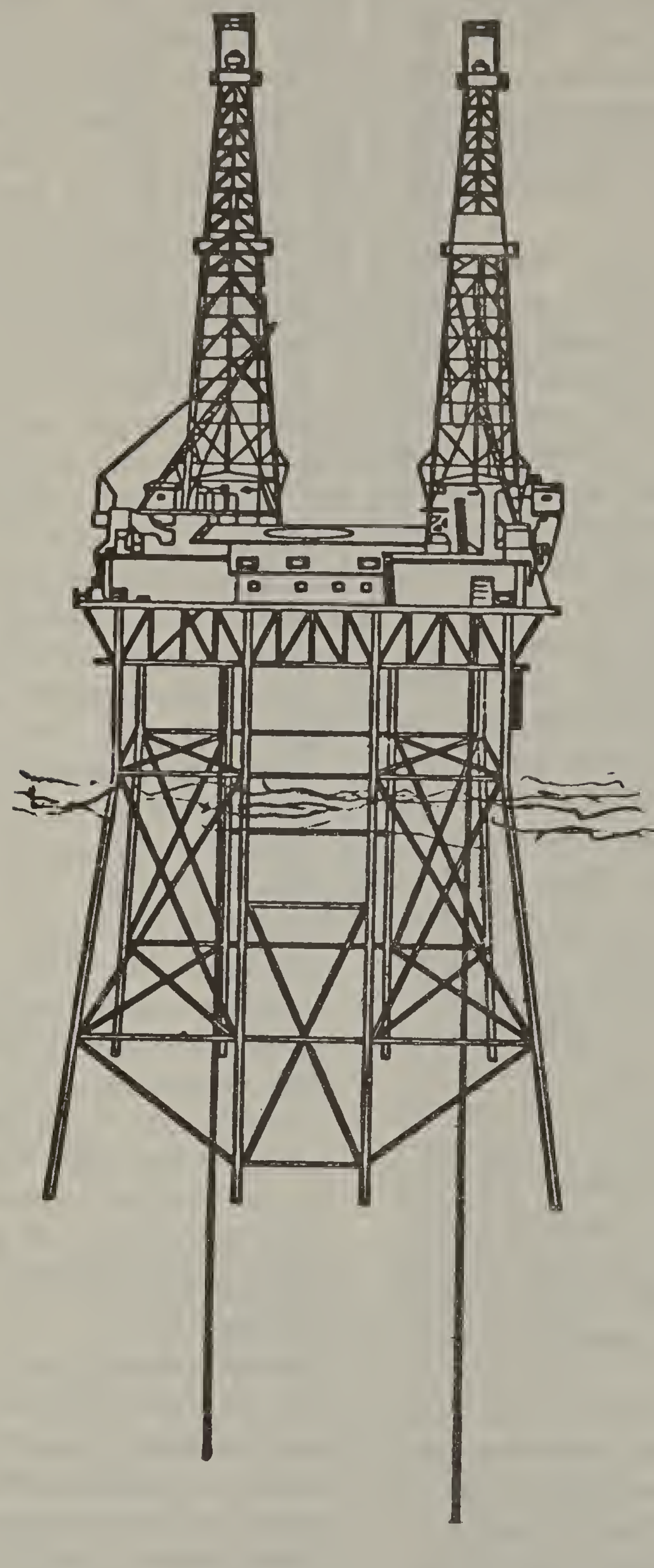


Figure C-4 Offshore development platform with drilling rigs in place

offshore platforms. Appropriate design procedures are outlined in API Recommended Practices RP 2A and various API specifications. These guidelines have been prepared to cover engineering design and operation of offshore structures and related equipment. United States Geological Survey Outer Continental Shelf Orders define regulatory approval procedures for platform design and installation.

There are at least three subsea production systems currently under development which are designed to serve multiple wells. They are described in the following section (Production). Each provides for gathering, measurement and control of well streams and enables, through the flowline (TFL), well maintenance. Subsea completions will result in sea floor obstructions that could foul trawling gear; however, should a trawl snag a subsea completion the possibility that it would damage any of the wellhead assembly to the extent of causing uncontrolled flow is remote because of the strength and durability of the material that would be used in the sea floor structure.

Wells usually are produced through tubing placed inside the final or production string of casing. During tubing installation, the blowout preventers remain in use to ensure control of the well. A system of in-tubing safety valves, plus other casing and tubing valves at the surface or sea floor, is installed to control well flow. Actuation is usually at the producing platform.

Of major concern in the operation and control of every production platform are the downhole control devices. Production tubing is fitted with one or more safety valves that are installed and located at least 30 meters below the mud line or sea floor. In the past, velocity actuated choke valves ("storm chokes") designed to shut off production when the flow rate exceeds predetermined limits have been used. Such valves should close if surface equipment failure results in an excessive flow through the tubing. These chokes are particularly susceptible to failure from internal erosion in areas where sand is produced along with the oil and gas.

Certain types of subsurface fail-safe valves do not depend on the velocity of well fluids for actuation, but are held open by hydraulic or other fluid pressure applied from the surface. The valve is designed to close automatically, shutting off the flow of fluid from the well in the event some undesirable situation on the platform interrupts the pressure holding the valve open. Essentially all wells drilled since December 1, 1972, are equipped with valves that are actuated from the surface. These valves provide highly reliable protection and may be tested frequently to insure proper operation. Their use will increase costs significantly, but the need for more reliable valves has been shown by past incidents in the Gulf of Mexico and elsewhere. The increased degree of safety offered by use of the fail-safe valves should justify their installation.

Technology presently exists to install platforms in water depths to at least 300 meters, and industry contends that the practical limit can be extended to 365 meters. It is assumed that since water depths encountered in this proposed sale will be 200 meters or less, development drilling and production platforms can be used. In typical template-type structures, the lower portion, or jacket, is barged to sea, launched, upended and secured to the sea floor with piling driven through the legs. The deck section is then lifted into place and secured by welding.

The drilling rig, power plants, generators, living quarters, storage sheds and other components, constructed in modular form, are added to the platform, and development well drilling commences. Equipment anticipated for use on deep water platforms is similar to that being used safely in current shallow water operations, and will be installed and operated in accordance with safe practices accumulated from industry experience. These practices are incorporated in OCS Orders and specify multiple, redundant controls and safety devices including safety shut-in valves, high-low pressure pilots, high-low level controls, high-temperature shutdowns, gas detectors, shielded ignitions, fire prevention and detection equipment, and pressure relief systems. Drain and sump systems are also designed to collect any spillage that might occur on the platform. The sequence of drilling operations for development and production wells is essentially the same as for exploratory wells.

Blowout preventers as well as downhole control devices have proven to be extremely valuable in time of accidents and emergencies to prevent large amounts of oil from escaping into the environment. When hurricanes have passed through offshore oil and gas fields, entire platforms have been swept away with only a minimal spillage.

Blowout preventers on drilling wells and the redundant combination of wellhead valves and subsurface safety valves have proven effective in maintaining control of wells when the normal controlling devices (drilling mud and production regulators and chokes) have failed. Once shut-in, the wells can be reentered through either the blowout preventers or wellhead valve with drill-pipe or tubing to perform remedial work and bring the well back under control. This can be done if the blowout preventer or wellhead is on the sea floor the same as if they were located on a platform. However, should a well get completely out of control and crater around and outside the surface casing so that the well could not be reentered, then an offset relief would have to be drilled.

As with exploratory drilling, the casing and mud programs for each development well must be approved by the Geological Survey before a drilling permit is issued.

Production

The production platform contains all the equipment and performs the same function as a field gathering station does at an onshore location. The fluid produced from the well is some mixture of gas, oil and water in varying proportions. Depending upon the flowing wellhead pressure, this mixture may be subject to as many as three stages of gas-oil separation. The stage separation process recovers the driest gas and the largest volume of liquid.

The gas may be further processed through scrubbers to remove any entrained oil, water or other impurities before it is compressed and sent ashore by pipeline. If there is insufficient gas to sell to a trunkline, it may be reinjected into the producing formation as a pressure maintenance measure, used for gas lift, or used as engine fuel to drive pumps and compressors. Only on rare occasions is gas flared and then a permit from the OCS Area Supervisor of USGS is required.

The oil/water mixture that comes from the gas-oil separator goes first to a free water knock-out where the free water is separated by gravity from the oil. Should some water be emulsified with the oil, this mixture is sent through heater and/or chemical treaters to break the emulsion and separate the oil and water. The oil is pumped ashore by pipeline and the water is further filtered and treated to meet EPA effluent standards before being disposed of overboard.

The production platform is basically that of the development platform minus the drilling rigs. Facilities consist of gas-oil separators, oil-water separators, gas scrubbers, compressors, pumps, storage tanks, instruments, and controls. As mentioned previously, multiple redundant controls and safety devices are required by OCS operating orders to prevent accidents and degradation of the environment.

The possibility does exist that subsea completions would be used as a result of this proposed sale. Wells can be drilled vertically from locations conforming to the desired spacing pattern of the field. In this case flow lines are required from each well to a common point. This common point may be either a surface production facility, an ocean floor production and test manifold, or, possibly, a subsea production facility.

There are two principal drawbacks in developing a field in this manner.

There is a practical limit to the length of flow line that can be considered. Depending on the production characteristics, wellhead pressure and fluid viscosity in particular, there will be a pressure drop per unit length of line. In some cases this pressure drop could be enough to prevent production from reaching the central collecting point and certainly, as the reservoir pressure declines during the life of the field, problems will develop.

Depending on the type of well completion, the production tree in particular, flow line lengths are critical. If the well is to be maintained by divers and/or surface vessels, the flow line length may not be too important, but where maintenance is to be carried out by pump down, through the flow line (TFL) tools, the length of flow line would be important. Also, if the well is to be remotely controlled, hydraulic lines and/or electric cables may be required to actuate well controls. These would normally parallel the flow line.

Normally, subsea wells are drilled within three miles of the central collecting point but longer distances are being planned. If conventionally moored vessels are used in field development, and later in field maintenance, the presence of a number of lines on the sea floor may hinder the use of anchors and increase the hazard of rupturing the lines.

If the productive formation is deep enough below the sea floor, wells can be drilled directionally from a common site on the sea floor to bottom in widely-spaced locations to meet the needs of optimum field spacing. Generally, some type of base plate or template is employed to space well heads. These templates may be elaborate and combine functions other than wellhead spacing or the templates can be simple and merely replace the temporary guide base.

This system is called the cluster concept for subsea completions and the wells can be conveniently connected to a common subsea test and production manifold. In this case only two lines

carrying production to the surface are required, one to carry the total production from the cluster and the second to carry an individual well's production to a test facility. Depending on the field development plan, additional lines to handle well and manifold control functions may also parallel the flow lines.

Down hole completion procedures for subsea wells are as discussed above. After tubing is hung and plugged, the BOP stack is removed and the wellhead is set and connected in place.

Wellhead equipment for subsea wells is functionally similar to the equipment described for platform wells and includes all the safety devices previously described. The control equipment is necessarily modified in accordance with the type of basic control design—that is diver operated, remote control from the surface, control at atmospheric pressure in encapsulated wellheads, etc.

In the simplest form the subsea production tree can be the same as those used on land. The tree is installed by divers and manipulation of well controls would also require divers. Divers also make up the flow line connections. The tree valves can be controlled hydraulically from a remote point through hydraulic control lines. Four trees of this type were installed by Phillips Petroleum Company in the El Molino Field in the Santa Barbara Channel in 1963 in 60 meters of water.

The problem with diver operated systems is the diver depth, though present working dives are routinely carried out in water depths to 183 meters and they have been carried out in depths of 330 meters.

A remote controlled, hydraulically manipulated tree is installed without diver assistance using the same techniques as those used to make up blowout preventer and riser pipe connections during drilling. All valves are controlled hydraulically, or electro-hydraulically where distance attenuates hydraulic response time from a remote control point. All valves are also of the fail-close type, which means they will automatically shut in the well should loss of hydraulic pressure occur. Four of these trees are installed in 70 meters of water in the Ekofisk field in the North Sea operated by Phillips Petroleum Company.

An encapsulated tree is a conventional tree installed in a chamber that is maintained at atmospheric pressure and includes a means of access from a personnel vehicle. The personnel vehicle can be considered a diving bell with means of connection to the subsea chamber over the wellhead. In this manner, non-diving technical personnel have access to the wellhead controls and can perform all of the functions possible on a land well, including wire line work.

Several subsea production systems have been developed, and they are discussed more fully below. One of these, the Lockheed system, was installed by Shell Oil Company in the Gulf of Mexico in September 1972, in 114 meters of water. In 1973 the well was successfully reentered for routine maintenance.

This concept can be expanded to include a complete production system. The advantage of course is that well work can be performed at surface conditions (atmospheric pressure) and that the work can be done using conventional oil field tools and techniques with no reliance on sophisticated remote control techniques. These systems are presently viable to at least 457 meters and even greater depths can be anticipated in the future.

A subsea manifold would perform the same function as a manifold on a surface production installation. The purpose of this series of valves is to collect the production from several wells and combine it to a single stream for delivery to a separation facility. There must also be a means of segregating individual well production for metering and testing. This is accomplished by the series of valves included in the manifold.

The manifold, which can be operated hydraulically or electro-hydraulically from a remote control point can be "wet" or it can be encapsulated. The value of such a system is to permit a cluster of subsea wells and avoid the number of flow lines required if wells were widely spaced.

A subsea production system was installed in the Zakum field of Abu Dhabi Marine Areas Ltd. in the Arabian Gulf in 1970. The field is operated by British Petroleum and Cie. Francaise du Petroles. The system is electrically operated and diver maintained; the site is in 21 meters of water and was selected so as to be readily available for diver maintenance. The system includes all well controls, a gas-oil separator, and a gas driven generator for electrical power. The system is purely experimental, but is operating and indicates what may be possible in the future.

Exxon's submerged production system (SPS) has been proposed as a possibility for the development of the Santa Ynez Unit in the Santa Barbara Channel and was discussed in the U.S. Geological Survey's environmental impact statement covering this subject. Exxon's submerged production system (SPS) which provides facility for three wells has successfully completed land tests. The SPS is a cluster of subsea wells and associated production controlling, separating and pumping equipment mounted on a subsea structure. The produced fluids are transported to surface processing facilities via pipelines to shore, to a platform or to a production riser connected to a floating vessel. The subsea equipment is remotely controlled and monitored from the surface facilities by an electro-hydraulic supervisory control system. Pump-down tools are used to service wellbore equipment and a manipulator operated from the surface is used to replace non-operative subsea equipment. All elements of the system have been designed and land tested. Work is in progress to perform an offshore test of the complete system.

The system essentially consists of a cluster of wells drilled through a seafloor template and connected through a manifold system. The manifold system is surrounded by a track on which a wellhead and manifold manipulator runs. The manipulator is controlled from the surface and can control all well control functions. Provision is also made for access to the annulus of each well. The manipulator maintenance system is shown in Figure 5.

The submerged production system (SPS) provides equipment and procedures which span the production requirements of a field from the time development drilling starts to field abandonment and from wellbore equipment at the completion interval to the processing equipment at the common carrier custody transfer point. The SPS is composed of eight functional subsystems as follows: 1) the drilling and completion subsystem, 2) the manifold subsystem, 3) the remote control subsystem, 4) the pump/separator subsystem, 5) the template subsystem, 6) the pipeline connection subsystem, 7) the production riser and floating facility subsystem and 8) the maintenance manipulator.

The final series of land tests on a prototype, 3-well, subsea production manifold and a maintenance manipulator were performed in a water-filled pit where the underwater production equipment was automatically operated to control well streams simulating liquid, gas-liquid, and sand laden production. In this testing, the prototype equipment met or exceeded design specifications. In addition, the maintenance manipulator was deployed from a surface vessel to a mock-up installation in 130 meters of water to demonstrate its ability to land on its track which surrounds the underwater equipment. This development test, when coupled with the pit test, proved the manipulator to be capable of performing the maintenance tasks. Results of tests on the SPS wellbore equipment and on a pre-prototype pump/separator subsystem have indicated the utility of these equipment subsystems in performing their functions. Tests simulating operating conditions have permitted the design of prototype pipeline connecting equipment needed for the SPS.

An offshore test of the Exxon SPS is underway in the Gulf of Mexico off Louisiana. In this offshore test, installation, production and maintenance operations in the Gulf of Mexico will be performed in a manner representative of producing a deepwater field with an SPS and the full-scale depth-capable equipment will be used. The purpose of the test is to evaluate the cost and performance of the equipment and technique during installation, operation and maintenance activities. The results of extensive land testing indicate that the equipment will function properly and this offshore test will provide data necessary to evaluate both equipment and procedures.

The test includes a template with producing equipment placed on the sea floor in 52 meters of water in West Delta 73 Field which is 43 km southeast from Grand Isle, Louisiana. Three wells in the test will deliver production to a manifold which surrounds the well bay, then to a subsea separator and fluid pumps. At that point, gas will flow via pipeline to the nearby "F" platform. Liquid will be pumped using submersible electrical pumps via an articulated production riser to producing facilities on the platform. The riser will be tested to confirm its capability although no oil will be loaded to a service ship in the pilot test. The test plan for the template calls for all work on the sea floor to be done remotely without the use of divers, simulating deep water application.

The template was fabricated and equipment installed and tested in McDermott's yard in Morgan

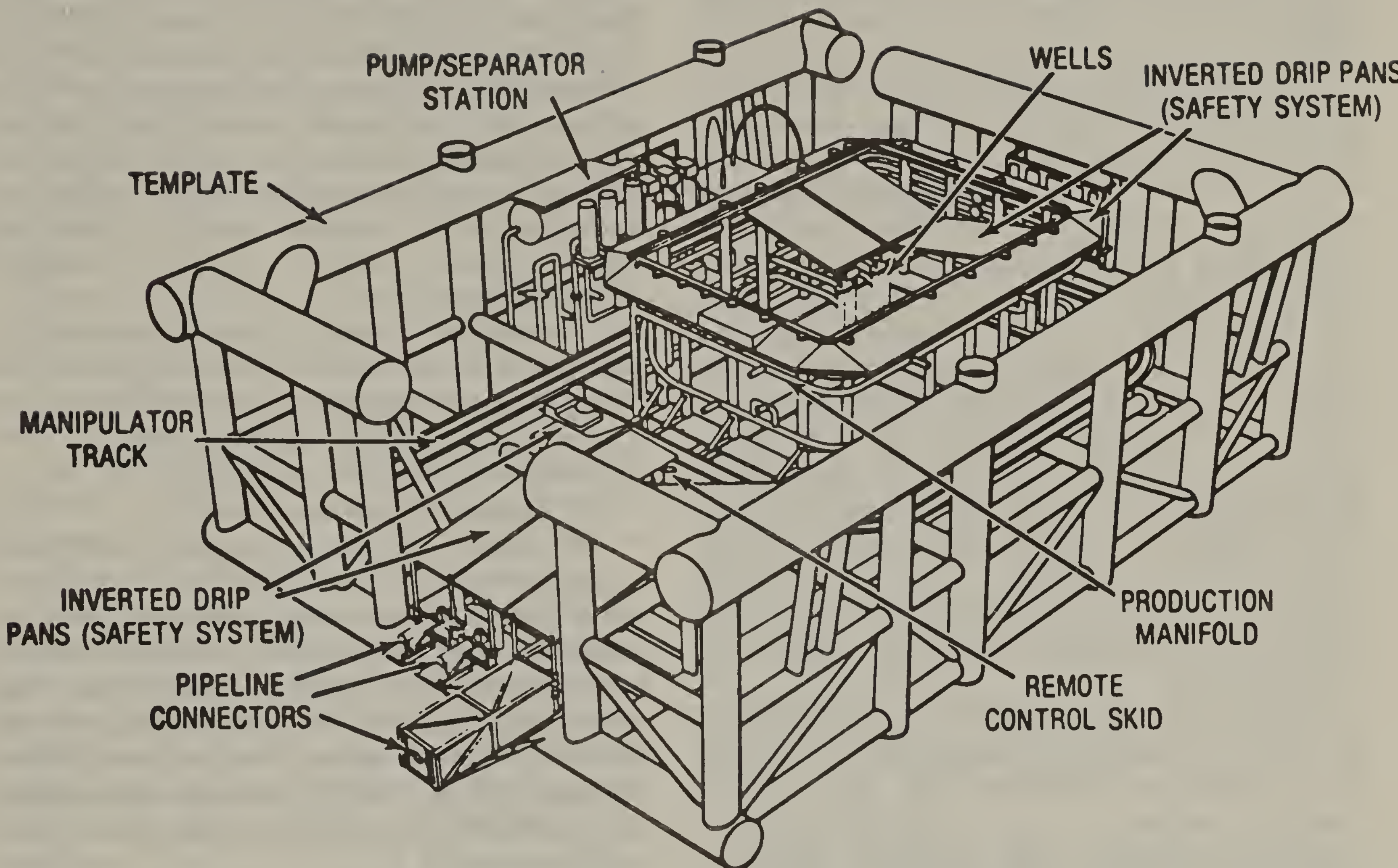


Figure C-5 EXXON SPS Manipulator System
(Source: EXXON Company, U.S.A., 1971, Supplemental Plan of Operations, Santa Ynez Unit

City, Louisiana, over a period of 15 months beginning in May, 1973. The template was launched much like a conventional platform jacket on October 19, 1974. Subsequently, the unit keelhauled under a drill ship, the Glomar "GRAND BANKS", then lowered to the sea floor with the rig draw works. Four pilings have been drilled in and cemented to the floor and the template leveled. Pump caissons have been installed.

Five pipelines have been laid and connected to the template by remotely controlled operations. Two of these lines (2.5–7.6 cm ID pump down tool line and the 20 cm gas line) connect directly to the "F" platform. The other three lines (a 7.6 cm ID pump down tool line, 7.6 cm ID gas injection line and 20 cm oil line), also terminate at the "F" platform by way of the production riser. The two cables, a 35 kv cable supplying power to the fluid pumps and a 5 kv remote control cable, have been laid. As of November 1975, three wells had been drilled and the maintenance manipulator deployed to make planned connections on the sea floor equipment. Pipeline pumps have not yet been installed. Although there have been problems as would be expected in a test of this magnitude, no basic flaws have been detected in the SPS to date.

The test will have a minimum duration of three years but producing and maintenance operations will probably be continued until they can no longer be justified.

Shell Oil Company and Lockheed Petroleum Services joined efforts to develop and field test an ocean-floor system for completing and producing wells. The system is based on the concept of housing more-or-less standard equipment in one-atmosphere chambers. The chambers can then be linked together with subsea pipelines to form a complete producing system. Servicing the equipment inside the chambers can be performed by experienced oilfield workers, transported to and from the chambers in a dry, one-atmosphere diving capsule.

The current joint program consists of three phases. Phase I, the Lockheed Petroleum Services (LPS) one atmosphere system was completed and installed in 1972, for Shell Oil Company in the Gulf of Mexico (Main Pass Block 290) at a 114 meter water depth. There have been no major technical problems with the wellhead chamber and the well has produced over one-half million bbls. of oil.

Phase II, the subsea manifold center, has been installed in Eugene Island Block 331 Field. Work has been temporarily suspended until spring 1976 awaiting better weather conditions. The LPS wellhead cellar is supported on the casing head housing and is surrounded by the guide frame whose base is one to two meters above the sea floor. This is all supported by a 75 cm diameter drive pipe penetrating the sea floor. Foundation for the manifold center is a barge that carries the system to the site and is sunk to form the base on the sea floor. All LPS equipment and materials have been carefully selected for the appropriate pressure rating and subjected to extensive testing. Every well is equipped with automatic fail-close valves and remote shut-in controls actuated hydraulically from the platform.

A control panel on the platform regulates all the sensing and remote functions and includes:

1) Remote actuation and position control of all remotely operated valves and chokes.
2) Pressure sensors in pipelines.
3) Sequential shut-in system.
4) Testing of the emergency shut down system (ESD).

An ESD condition will sequentially close the manifold center's hull valves and subsea Christmas-tree's fail-safe valves (all master and wing valves simultaneously). The tubing removable surface controlled sub-surface safety valves (SCSSV) at Eugene Island is a ball type which was updated from the storm choke used in Main Pass to meet OCS Order No. 5.

All oil and gas pipelines will be equipped with automatic shut-in valves connected to ESD and remote shut-in systems. Hydraulic lines are equipped with back-up systems if the ESD fails.

The third phase will consist of a subsea clustered well system. It is anticipated that data from this system will provide the sound basis necessary to project design and cost criteria for application in up to 914 meters of water.

In September 1973, Shell, utilizing the atmospheric diving system of Lockheed Petroleum Services, Ltd., successfully reentered and performed maintenance in a subsea wellhead chamber at atmospheric pressure in 114 meters of water in the Gulf of Mexico, offshore Louisiana. The primary purposes for the reentry were to locate and repair a leak in the hydraulic control system, observe the condition of the chamber and tree components after one year of operation, and provide diving experience for Shell personnel.

The chamber and internal components were found to be in excellent condition during the first dive. Nine dives were made and all work was completed as planned under ideal weather conditions during the seven day period.

In the first three years the well has produced 950,000 barrels of oil and 8.5 million cubic meters of gas and is currently producing at a rate of 950 barrels of oil per day and 20 thousand cubic meters of gas per day. Maintenance and remedial experience has included six TFL (through-the-flowline) operations, where tools are pumped through the tubing, to service subsurface controls and acidize the lower zone, and three entries into the WHC (wellhead chamber) for routine maintenance.

Two examples of the Lockheed system for wellhead equipment are shown in Figure 6. The chambers shown are those permanently installed on the wellhead and the upper hatch indicates where the service capsule is attached.

After the capsule is connected, the chamber below the capsule and above the entry hatch to the work chamber, is pumped dry and the atmosphere is tested prior to opening the hatches.

Subsea Equipment Associates Limited (SEAL) has been principally funded by British Petroleum, Mobil Oil Company, Compagnie Francaise du Petroles, Westinghouse Electric Corporation, and Group Deep, the latter a consortium of European Contractors. Associate members of the group include Conoco, Sunoco, Phillips, ELF/ERAP, and Petrobras.

SEAL currently has under development three subsea oil and gas production systems. Two of the systems undergoing tests are designed for use in foreign fields where high production rates are prevalent. SEAL is also testing a subsea oil production system in the Gulf of Mexico which is designed primarily for utilization with large numbers of domestic low-production wells of less than 1,000 barrels per day which in turn generally require significant maintenance. Sun Oil Company is participating in the test project in the Gulf.

Essentially, the SEAL system is similar to the Shell-Lockheed system where working areas are enclosed in atmospheric chambers and access is available through personnel transfer capsules lowered from a surface vessel. Systems have been designed for individual well completions, cluster type well completions, a production manifold station, a subsea separation facility and a subsea pumping station.

As in other similar systems a base plate is hydraulically connected to the wellhead. For a multiple well system the base serves as a drilling template for directionally drilled wells and part of the structural piping is used in the manifolding system for the wells. The subsea work enclosure is then connected to the base structure and has provisions for personnel entry through a hatch from a personnel transfer chamber. The configuration of the work chamber can be varied depending on the water depth, number of wells associated, production rates, etc. The chamber provides a dry working environment on the ocean floor at atmospheric pressure.

Phillips Petroleum Company is presently completing exploratory wells in the Ekofisk field in the North Sea in about 67 meters of water using this method. They are completing the well and connecting the base plate and lower master valve before releasing the drilling rig. The upper portion of the wellhead assembly (the work chamber and associated valves and piping) will be installed when production facilities are available. This installation can be made with a small support vessel without requiring the services of an expensive drilling vessel. Previously, exploratory wells were either abandoned, or temporarily abandoned. Abandonment represents a loss of considerable investment and if temporarily abandoned, a drilling vessel would be required to reenter and complete the well.

Another test of the SEAL system was made in the Gulf of Mexico. This involved a multi-well system and it is described in a paper titled "Subsea Manifold System" by Chatas and Richardson, Seal Petroleum Company. It is numbered OTC 1967 and was presented at the 1974 Offshore Technical Conference in Houston, Texas.

Testing started by simulating field production on dry land in 1971, in Long Beach, California, where the prototype was constructed. In 1972, the unit was transported to the Gulf of Mexico and installed in 75 meters of water, 245 meters from a Sun Oil Company production platform at Main Pass 293A. First tests were conducted by diverting production from wells on the platform through the manifold system. After processing, the production was returned to the platform; additional drilling operations were started in December, 1973, and the test was completed in September, 1974.

During the commissioning and check-out phase of the test, 56 entries by personnel were made into the subsea work enclosure (SWE). Most of these personnel were not divers, but regular oil company personnel. Over 90 automatic operations of pump-down tools were performed, principally to remove paraffin deposits in the wells. These tools were pumped through the flow line network, to the platform, down the well and returned. The personnel transfer bell used in these tests is capable of transporting five men into the subsea structure. The base of the SEAL Atmospheric System (SAS) and the subsea work enclosure (SWE) used in the Gulf of Mexico test are shown on Figure 7.

The SEAL Atmospheric System (SAS), which was tested in the Gulf of Mexico, was based on the use of a large habitat type structure permanently installed on the sea floor to house oil field equipment. The SAS system incorporates a subsea manifold system in which various oil field production equipment can be installed depending on the application.

The three major elements investigated in conjunction with the SAS Test Program were as follows: 1) the Subsea Work Enclosure (SWE), 2) the automatic production control system, and 3) automatic well maintenance system based on use of TFL (through-the-flowline) test.

A test separator located within the SWE was a vertical two-phase separator capable of handling produced volumes of approximately 400 bbl/day of oil and 760,900 scf of gas per day. Due to the characteristics of wells produced through the SWE during the tests, the separator was operated at full capacity and demonstrated repeatability of each well tested and correlated accurately with production data available on each well.

The separator instrumentation was of a conventional nature utilizing temperature, pressure, and differential pressure on a gas meter run, a net oil computer and a displacement meter to give quantity and percentages of oil and water.

A common approach in the SEAL systems has been the use of trained oil field personnel on the sea floor. The maintenance personnel are transported from the surface to the subsea structure in a Personnel Transfer Bell. Test operations have proven conclusively that the vehicles are efficient and can be operated safely.

Future applications of this concept would be as a manifold center, a test separator center or a complete oil production system. In a similar manner to the other systems, men are transported to and from the Subsea Work Enclosure (SWE) through the use of a Personnel Transfer Bell. The men perform their duties at atmospheric pressure.

Other submerged production systems are in the design or test stage. Deep Oil Technology, Inc., Transworld Drilling Company (a subsidiary of Kerr-McGee Corporation), and Standard Oil of California all have systems that have not yet been fully developed. The Transworld system is similar to the Lockheed and SEAL systems where an underwater work chamber at atmospheric pressure is utilized. The main difference is that wellheads would be maintained in a wet atmosphere except when work was actually in progress with the underwater work chamber in place. Construction is in progress on prototype models and the system is designed to be operable in water depths to at least 457 meters.

A possible production system where production from subsea wells is directed to a surface vessel containing separation equipment is more likely to be used in deep water where platform costs become prohibitive.

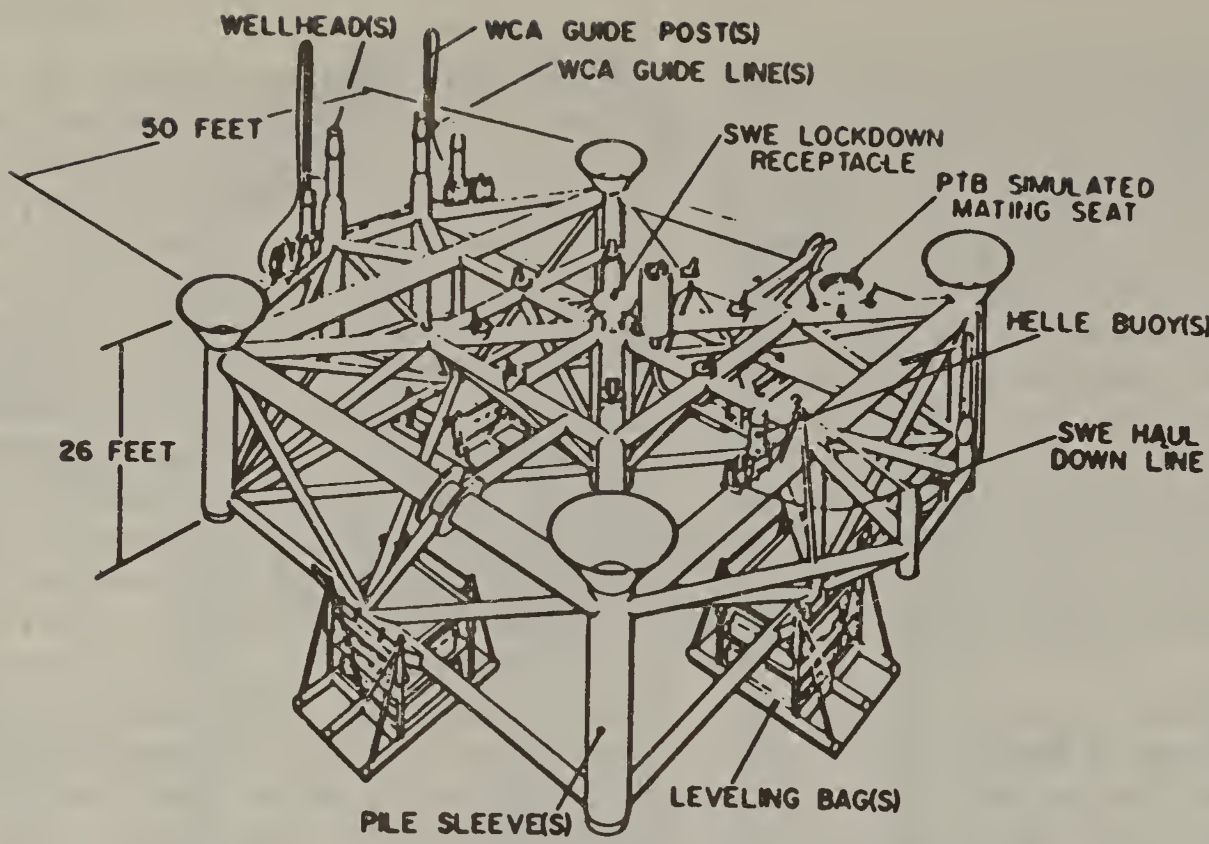
To meet the needs of producing large amounts of oil from deep water tracts with hard bottoms in the harsh physical environment of the North Sea, many petroleum companies have turned to the use of concrete platforms. These structures rest on the ocean bottom by virtue of the great weights—upwards of 300,000 tons (272,340 metric tons) or more. Each platform is completed onshore and then towed upright to the development site, where ballast tanks are flooded and the structure settles to the seafloor.

Figure 8 shows the designs of two North Sea platforms to be installed in about 152 meters of water. Each platform is similar in size and construction methods and will have storage capacities of 900,000 barrels of oil in the base.

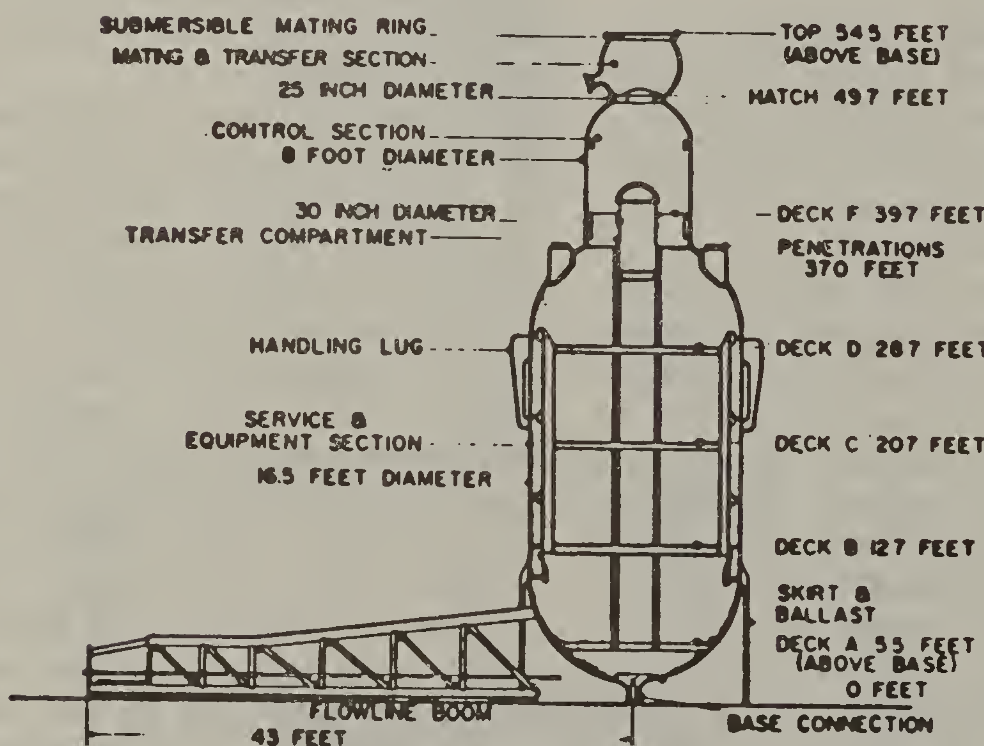
A large concrete storage tank has been in place in the North Sea field since 1973. This structure is 93 m in diameter and 90 m high and has a capacity of 1,000,000 barrels of oil.

Sea floor requirements of all these structures include (1) an even bottom, (2) strong bearing capacity of surficial and underlying sediments, (3) little lateral variability of these same sediments.

Because of the size of anticipated finds, expected production, production by pipeline, and availability of steel fabrication yards, it is not an-



a. Base & wellhead connector assembly



b. Subsea work enclosure

Figure C-7 Seal Subsea Manifold System
(Source: Subsea Equipment Associates, Ltd. (Also presented at the Sixth Annual Offshore Technology Conference, Houston, Texas, May 6-8, 1974)

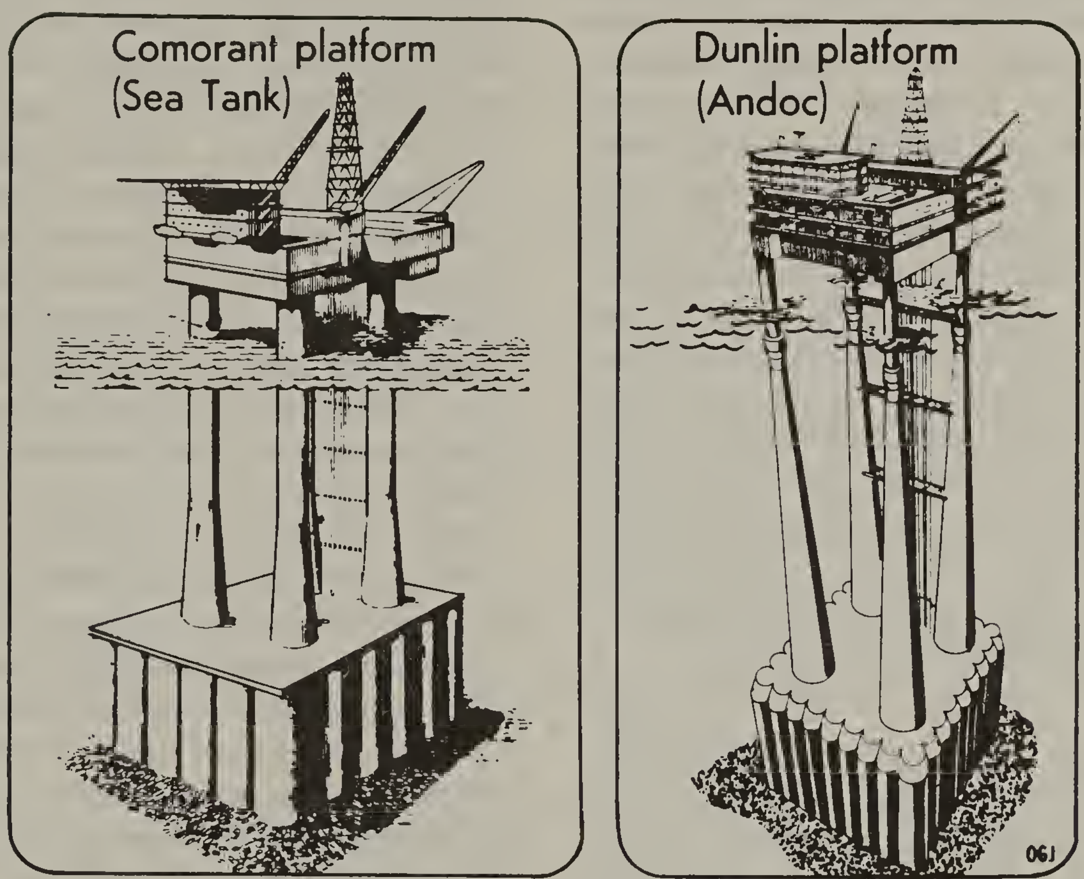


Figure C-8 Gravity Type Steel and Concrete Combination Drilling, Production and Storage Platforms. (From Oil and Gas Journal, May 27, 1974, Vol. 72 (21):34).

ticipated that concrete gravity structures will be used as a result of this proposd sale.

The waters associated with oil and gas reservoirs and which are frequently produced along with the oil and gas are called formation waters. It is highly unlikely that any of the produced formation water resulting from this proposed sale would ever be piped ashore. Both economic and environmental considerations weigh heavily towards choosing to treat and release the water into the ocean at the platform site or reinject it into subsurface formations. Reinjection is utilized where feasible as a secondary recovery technique by pumping formation water, under pressure, back into the lower levels of the petroleum-producing zone and thus maintaining good reservoir pressure. Disposal of formation water into other than the producing formation is not done because of the expense involved. This method of disposal requires a separate well plus some water treatment to insure that the injected water is compatible with the host reservoir. Formation water which is to be discharged into the ocean is first passed through a water-treating facility that removes all but traces of entrained oil. However, the water is still void of dissolved oxygen and contains large quantities of dissolved minerals, but in any case must meet EPA standards.

Since petroleum production involves the handling of flammable fluids under pressure, the safety systems control is of utmost importance to preclude hazardous conditions. Nowhere is this hazard greater than during workover, or remedial operations on a well in order to improve its production rate or to replace faulty downhole equipment. Since workover operations are potentially hazardous, they must be planned carefully, both to keep wells from getting out of control and to prevent or minimize the release of oil to the environment. Currently under review within the U.S. Geological Survey is a proposal to revise OCS Operating Orders to reduce or prohibit simultaneous production and drilling from the same platform. The restrictions would apply to workover operations as well as to drilling and production operations.

To reduce pollution, specially treated salt water that can be weighted with various materials is used for hydrostatic control when reentering the wells in wire-line or swabbing operations.

To increase production, acid or other fluids and suspended particulate matter may be pumped through the well bore into producing formations. The function of this treatment is to enlarge flow channels leading to the well. The spent acid returns up the well when production is resumed, and is handled as are other fluids from the well. Oil and water contaminated with spent acid are transported with the rest of the production to the refinery.

Sand produced along with the well fluids can cause the wells to plug, and "sand-up", periodically and must be removed. Other procedures to increase productivity and oil recovery include the injection of high-pressure steam, water, and/or gas into specially prepared injection wells. The water used for this purpose may be taken from the ocean or from formation water. Water too contaminated to be treated and discharged is either reinjected into formations or transported ashore for further treatment and disposal. Suitable precautions are taken to ensure that fresh water aquifers will not be contaminated by oil or salt water. Gas produced from the well may be reinjected for pressure maintenance where feasible or piped to shore for sale.

From the safety standpoint, completion and workover operations must be conducted carefully, and it is their critical nature that, in all likelihood, makes these operations safer than they otherwise might be. Operators of swabbing and wire-line units are well aware of the hazardous nature of their work and are extremely cautious. Despite the potential hazard, safety records during wire-line and swabbing unit work are excellent.

Offshore pipelines, particularly large diameter or long lines, are usually installed using a barge specially constructed for marine pipelining called a "lay barge". This barge is a self-contained unit including all of the facilities required to join the pipe by welding, cover the weld with protective coating, and to lower the pipe in place on the ocean floor. The pipe is coated on shore and delivered to the lay barge in uniform lengths or "joints" with the ends prepared for welding. Several anchors, at least two at each corner, are used to hold the barge in position. Joints of pipe are welded together on the deck of the lay barge to form a continuous length. When a weld is finished, inspected and coated, the barge is moved forward allowing the assembled pipeline to extend over the stern of the barge and to sag downward to lie on the ocean floor. A new length of pipe is added to the "forward" end of the

pipeline and the process is repeated. Making a high-quality pipeline weld requires a reasonable amount of time. Therefore to obtain rapid production, "assembly line" techniques are used allowing welding to take place at several stations simultaneously. To do this the work on the barge must take place in an almost level position. From the barge to the ocean floor the pipe will assume a double curve or "S" shape. If the pipe is too stiff to reach the bottom unsupported, a buoyant pontoon or slide called a "Stinger" is used to provide support for the upper section of the pipeline. To help support the weight of the pipe and to prevent buckling, a carefully controlled tension force is applied to the pipe by constant tension machines mounted on the barge.

The pipe assembly process utilizes the latest technology and the best welding techniques currently available. All joints are given a complete X-ray inspection for quality and then covered with corrosion resistant material prior to leaving the barge. The shore pipelines are designed and installed to meet the same codes and specifications as onshore pipelines, such as API, ANSI, ASME, etc. After the line is completed, it is tested to make sure that it has been properly installed and will withstand the anticipated operating pressures safely. The pipe is further protected by cathodic protection systems to supplement the corrosion resistant coating.

The technology now exists to lay large diameter pipelines in depths of 350 meters or more in harsh environments. For example, the semisubmersible pipelay/derrick barge Semac I, presently under construction in Mobile, will be capable of laying large diameter pipe in up to 350 meters of water in sea conditions encountered in the northern North Sea. With additional equipment the unit will be capable of laying pipeline in even deeper water (USGS, Written Comments, DES Proposed OCS Lease Sale No. 40, 1976).

Burial is effected by jetting sediment away from underneath the pipeline and allowing it to sink into the resulting trench. The equipment used in this operation consists of a work barge equipped with high volume/high pressure water pumps and air compressors. From the barge, a multiple membered towline consisting of a strength member, water line, and air line extends downward to a U-shaped structure which straddles the pipelines and glides along it on rollers. Affixed to the U-shaped jetting device are several nozzles which direct water and air, under high pressure, ahead and below the pipeline. Sediments are blasted out of the narrow trench by the water jets, partially lifted by the air and deflected to the sides by various types of fins. The suspended sediments fall diffusely along either side of the trench. As the jetting device is pulled forward, the pipeline settles into the trench and is partially buried quite soon by the reworked sediment as it slips and settles back into the depression. Complete burial and restoration of original bottom contours may require additional time. In shallow waters, experience has shown contour restoration to be quite rapid, whereas in deeper waters, more than a year may be required.

Even though a buried line is protected from fluid forces it is not necessarily stable. If it is too light, it will gradually work its way up through the soil and become exposed to the water forces. If it is too heavy, it will gradually sink in the soil and impose additional tensile stress in the line. Design procedures for determining the vertical stability of the line in sands and clays have been developed and are available in the industry.

Difficulties have been experienced in burying pipe in cohesionless sands. In this case the sand will often refill the jetted trench before the pipe can settle into it. Another method, fluidization of the sand, enables successful burial in this type of substrate.

Difficulties in trenching in hard bottom areas may be resolved by utilization a remote-controlled trenching machine which is capable of burying pipelines beneath the seabed at water depths to 1,640 ft. The machine attaches to a mother ship by control cable which directs the excavator's eight propeller-thrusters, four special ballast tanks, clamps and digging head. It descends to the ocean bottom "homing in" with radar and television on the prelaid pipeline to be buried.

To prevent corrosion, pipelines are carefully coated with such material as epoxy compounds or thick asphaltic mastic. If extra weight or mechanical protection (from fisheries trawling for example) is needed, these, in turn, are covered with a layer of dense concrete. The lines are protected from electrolysis by both impressed-current systems and by sacrificial anodes (zinc is commonly used). Corrosion prevention measures are now required by 49 CFR Part 195. Although offshore pipelines are relatively inaccessible as compared to onshore pipelines, they nonetheless can be repaired by divers. Methods of using sub-

mersibles to latch on to a subsea line and repair it with mechanical arms and special tools are under study and nearing the point of practical demonstration.

As in the case of workover operations, the expense of the pipeline installations, coupled with the catastrophic implications for the local marine environment should a major break occur, have combined to dictate a highly conservative design, emplacement, and operating philosophy.

As the pipeline construction approaches and traverses the shoreline, it is buried deep enough to avoid its being exposed by storm-associated beach erosion.

Onshore, the pipe laying method depends upon the type of terrain transgressed. If a pipeline were to be allowed to cross wetlands in which there was no firm ground to support equipment, a canal 12 to 15 meters wide would be needed. Lay barges are usually utilized in such areas. The dredged material would be placed alongside the canal and form a low, flat levee. With required openings and bulking (plugging the ends), erosion and salt water intrusion would be minimized, as would disruption of drainage patterns; although these problems may still persist to some degree. In firmer wetland areas; a smaller canal, about three meters wide would be dredged and backfilled. On firm land, the routine trench and backfill method is used which is the same technique by which water and sewer lines, cables, and so forth are buried.

A rough estimate of the width of land disturbed by pipelines laid through wetlands or on land would be 15 to 18 meters disturbed by equipment and a band of perhaps nine to 12 meters of soil and vegetations removed. On land, a swath of perhaps 15 meters would need to be maintained free of trees and large shrubs to permit maintenance vehicles access and surveillance for leakage.

The safe operation and maintenance of a pipeline system requires several redundant monitoring systems to ensure the integrity of the line and detect leaks. The primary leak detection system in use (required on all lines built after March 13, 1970, by 49 CFR Part 195.406 and 195.408) is a set of automatic pressure sensing recorders on both ends of each pipeline system. These devices are equipped to either shut down the flow automatically or sound an alarm to alert personnel of an abnormal pressure level. In this way, a leak of substantial rate is detected immediately. This system is insensitive to leaks which do not produce a decrease in line pressure greater than 300-500 psi. It is essentially a safeguard to prevent the escape of large volumes of oil due to a catastrophic line break.

The second system of leak detection is the routine patrolling of the offshore wetlands routes by boat or aircraft, and onshore by wheeled vehicle or aircraft. A minimum patrolling frequency, with intervals between inspections not exceeding two weeks, is required by 49 CFR Part 195.412, but in actual practice is performed more often. This type of monitoring would result in the detection of all sizes of leaks of course, but would be of little consequence in preventing the loss of a large amount of petroleum in the event a large line were severed. The appeal of a system of regular pipeline patrolling is that it allows detection of small leaks and therefore complements the pressure-sensing system described above. With volume of airborne and waterborne traffic expected over the potential oil producing area of the South Atlantic, it is considered highly improbable that any spill would go undetected for any appreciable length of time.

The third system for leak detection consists of a series of volume-recording flow meters on either end of a pipeline system. Because nearly all crude oil moves from OCS areas to shore by common carrier lines, it must be metered in the offshore pipeline gathering system and again at the onshore pipeline terminal in order that each producer be properly credited for his share of the common stream. The flow sensors continually measure input and output in real time; thus when attendant personnel record these readings for inventory control they are able to discover a decrease in output which would indicate the possibility of a leak. This is usually done on a shift schedule, once every eight hours or more frequently.

One more safety feature which would be built into all pipelines resulting from this proposal, according to industry spokesmen, is that remotely operated mainline block valves will be provided at remotely controlled pipeline facilities in order to allow isolation of segments of the pipeline. Isolating valves are required by CFR 195.260 and remote operation of these valves, while voluntary, would be one of the primary objectives of a remote controlled pipeline facility. Table A shows

the relationship between the diameter of a pipeline and the volume contained per kilometer of line.

Surveillance of pipelines can be performed by a variety of means. Side-scan sonar can be used to locate the pipeline and determine if it is buried. Underwater TV cameras can be extended from a vessel to examine the pipeline without using more expensive means. Divers can go down to actually inspect the line, burial depth, and condition of coatings. Miniature submarines can perform the same tasks with the added advantage of shirt sleeve environment, longer underwater duration, radio contact with the surface, and close examination of seafloor conditions by trained technicians. Measurements of cathodic-protection of the pipelines can be taken by divers and from manned submarines.

Appendix D

Memorandum of Understanding Between Bureau of Land Management and U.S. Geological Survey for OCS Pipelines

This Memorandum of Understanding is entered into in order to define clearly the administrative and operational roles of the Bureau of Land Management (BLM) and the Geological Survey (USGS) relating to pipelines on the Outer Continental Shelf (OCS), to provide consistent and standardized procedures, and to minimize or eliminate dual and overlapping functions.

Unless otherwise provided herein, pipelines are defined as any line transporting oil, gas, water, sulphur or other minerals, including lines sometimes referred to as flow on gathering lines.

The objectives of this Memorandum of Understanding are to:

A. Provide an efficient mechanism for approving pipeline routes through the submerged lands of the OCS.
B. Initiate measures to provide safety and to minimize or eliminate environmental damage which may be associated with the installation and operation of pipelines originating on the OCS.
C. Be responsive to the interests of the oil and gas industry, other users of the OCS, and the public with respect to pipelines.
D. Streamline implementation of the regulations and procedures for more efficient and uniform administration of the Department's authority with respect to pipelines.

PIPELINE MANAGEMENT

I. BLM Role

A. Conduct pipeline routing studies and, with the concurrence of the USGS, designate pipeline corridors on the OCS for all pipelines other than flow or gathering lines within the confines of a single lease or group of contiguous leases under unitized operation or a single operator.
B. Maintain a central office of record for the location of all existing and future pipelines as specified in paragraph I.A. and associated structures on the OCS.
C. Receive applications for rights-of-way for pipelines to be installed on the OCS pursuant to 43 U.S.C. 1334(c) and 43 CFR 2883.
D. Prepare environmental assessments, pipeline system planning studies, economic studies, and environmental impact statements when necessary or appropriate, prior to approving applications for rights-of-way pursuant to 43 U.S.C. 1334(c) and 43 CFR 2883.
E. After considering the potential impact of the pipeline on the environment, the relationship of the application to existing pipeline routes on the OCS, and other factors, approve or disapprove the application pursuant to 43 CFR 2883.
F. Conduct field studies relating to the long range environmental impact of all pipelines and associated structures, thereby providing a basis for continuous assessment of existing environmental safeguards applied to such pipelines.

II. USGS Role

A. Consider all applications from a lessee or operator for a right of use and easement to construct and maintain pipelines and associated structures on the OCS pursuant to 30 CFR 250.18 and 250.19. Prior to granting approval of such applications for any pipeline other than flow or gathering lines within the confines of a single lease or group of contiguous leases under unitized operation or a single operator, consult with the BLM so that the routing of such pipelines may be coordinated with existing lines or designated pipeline corridor.
B. Review technical aspects of OCS pipeline design, installation, maintenance and operation in accordance with appropriate regulations and standards designed for safety and environmental protection, and to avoid undue interference with other uses of the OCS and its superjacent waters.
C. Prepare environmental assessments or impact statements when necessary prior to approving applications filed pursuant to 30 CFR 250.18 and 250.19.
D. Provide the BLM with the location, as installed, of all pipelines approved by the USGS as specified in paragraph II.A.

PROCEDURES

1. BLM will receive right-of-way applications pursuant to 43 CFR 2883 for pipelines and associated structures for the transportation of oil, gas, sulphur and other minerals on the OCS. A copy of the application will be sent to USGS for review. The reviews by USGS will focus on the technical aspects of OCS pipeline design, installation, maintenance and operation in accordance with appropriate regulations and standards designed for safety and environmental protection, and to avoid undue interference with other uses of the OCS and its superjacent waters. The BLM will issue a decision granting the right-of-way after having been notified in writing by the USGS that the technical aspects of the proposed pipeline are acceptable. BLM will prepare environmental assessments and impact statements prior to granting such pipeline rights-of-way when necessary or appropriate.
2. The USGS will approve rights of use and easement for gathering and flow lines pursuant to 30 CFR 250.18 and 250.19. For any such pipelines other than flow or gathering lines within the confines of a single lease or group of contiguous leases under unitized operation or a single operator, the USGS will transmit a copy of the pipeline application to the BLM. The BLM will review the application as to whether the pipeline route conflicts with any existing or proposed pipeline and pipeline corridors or would otherwise not be consistent with good pipeline management for the OCS. The BLM will advise the USGS in writing of the results of its review prior to a USGS determination for approval or disapproval of the application.
3. The BLM will conduct field studies relating to the immediate and long term environmental impact of pipelines and associated structures on the OCS in order to assess the adequacy of environmental safeguards. Reports of the results of the BLM field studies with recommendations for minimizing the impact of pipelines on the environment will be released to the public and distributed to appropriate agencies with jurisdiction over pipelines on the OCS.
4. The BLM and USGS will periodically review existing procedures for reviewing applications and issuing rights-of-way and rights of use and easements and propose improvements in such procedures as appropriate. The procedures shall include the assessment of the environmental impact and the minimization of the number and locations of pipelines on the OCS.
5. The BLM and USGS will consult with each other in the preparation of environmental analyses and impact statements and will also consult with the Bureau of Sport Fisheries and Wildlife, the National Park Service, the Bureau of Outdoor Recreation, and other Federal and State agencies as appropriate.
6. The BLM will assume the responsibility for overall studies of pipeline routing on the OCS and, with the concurrence of the USGS, designate pipeline corridors for all pipelines other than flow or gathering lines within the confines of a single lease or group of contiguous leases under unitized

operation or a single operator. To assist in this, the USGS will furnish BLM with a copy of all approvals and drawings showing the proposed and installed locations of all pipelines, as described in this paragraph, and associated structures erected in connection with approvals of rights of use and easements.

/s/ V. E. McKelvey
Director, USGS

/s/ George L. Turcott
Director, BLM

August 1, 1974

Appendix E

Secretarial Order Number 2974

UNITED STATES DEPARTMENT OF THE INTERIOR OFFICE OF THE SECRETARY

Washington, D.C. 20240

JANUARY 19, 1977

Order No. 2974, Revised

Subject: Inter-bureau coordination in the Outer Continental Shelf (OCS) minerals program

SEC. 1 PURPOSE

The purpose of this order is to improve and formalize the planning and operating functions of the OCS minerals program by enabling the Bureau of Land Management (BLM) and the Geological Survey (USGS) to obtain expert advice from each other and from the Fish and Wildlife Service (FWS) and the National Park Service (NPS) with respect to environmental research and monitoring and operational activities associated with the OCS minerals program.

SEC. 2 ENVIRONMENTAL RESEARCH AND MONITORING

Environmental research and monitoring activities are those data collection activities conducted in specific geographic areas as a part of the OCS mineral leasing program. These activities are carried out in the context of a BLM program for administration, management, funding, and constructing of baseline studies, which includes bench mark data collection, subsequent monitoring, and special investigations. For the purpose of this order, bureau responsibilities are as follows:

(a) The BLM will consult with FWS and others, as appropriate, in designing the studies. In this connection, BLM will inform FWS of its study plan schedule and request FWS recommendations concerning:

(1) specific elements to be incorporated in studies (including scope, intensity, timing, required funding, etc.)

(2) allocation of funds and level of effort among various study elements.

(b) FWS and BLM shall, by mutual agreement, provide for FWS involvement in the performance or management of studies under any of the arrangements detailed below:

(1) FWS may perform or manage particular studies or specific study elements as may be determined by mutual agreement among FWS, BLM, and others as appropriate. BLM and FWS shall develop a memorandum of understanding which provides for reimbursement of stipulated study costs to FWS and other pertinent activities under this arrangement.

(2) FWS may perform or manage elements of a larger study which another Federal agency manages for BLM. In this instance, FWS would arrange with the other Federal agency for its participation.

(3) FWS, acting in effect as sub-contractor, may perform or manage elements of a comprehensive study effort which is managed for BLM by a contractor, e.g., a university consortium.

(c) FWS will participate with BLM and others, as appropriate, as a member of the OCS Technical Proposal Evaluation Committee.

(d) FWS will participate with BLM in monitoring those study elements of special interest to FWS.

(e) FWS will participate in the overall study program design for each separately identified geographical area in which baseline or other studies are planned.

(f) If, for good and sufficient reasons, FWS does not agree with the overall study program designs as prescribed in paragraph (e) above and is unable to secure mutually acceptable changes through discussions with BLM, the issues will be referred for resolution through the appropriate Assistant Secretaries to the Assistant Secretary--Program Development and Budget (AS-PD&B).

SEC. 3 CULTURAL RESOURCES ASSESSMENT STUDIES.

Cultural resource activities are those archeological and historical data collection and assimilation activities conducted in specific geographic areas as a part of the OCS mineral leasing program. These activities are carried out in the context of a BLM program for administration, management, funding, and constructing of regional studies, which includes data collection, synthesis and special investigations. For the purpose of this order, bureau responsibilities are as follows:

(a) The BLM will consult with NPS and others, as appropriate, in designing the studies. In this connection BLM will inform NPS of its study plan schedule and request NPS recommendations concerning:

(1) specific elements to be incorporated in studies (including scope, intensity, timing, required funding, etc.)

(2) allocation of funds and level of effort among various study elements.

(b) NPS and BLM shall, by mutual agreement, provide for NPS involvement in the management of studies under the following arrangement: NPS may manage particular studies or specific study elements as may be determined by mutual agreement among NPS, BLM and others as appropriate. BLM and NPS shall develop a memorandum of understanding which provides for reimbursement of stipulated study costs to NPS and other pertinent activities under this arrangement.

(c) NPS will participate with BLM and others, as appropriate, as a member of the OCS Technical Proposal Evaluation Committee.

(d) NPS will participate with BLM in monitoring those study elements of special interest to NPS.

(e) If, for good and sufficient reasons, NPS does not agree with the overall study program designs as prescribed in paragraph (a) above and is unable to secure mutually acceptable changes through discussions with BLM, the issues will be referred for resolution through the appropriate Assistant Secretaries to the Assistant Secretary--Program Development and Budget (AS-PD&B).

Sec. 4 OCS Operational Activities

OCS operational activities refer to the implementation of OCS regulations administered by BLM under 43 CFR, Parts 2883 and 3300 and USGS under 30 CFR, Part 250.

(a) When an OCS area is initially being considered for leasing, the Director, BLM, shall request, pursuant to 43 CFR 3301.2, a Fish and Wildlife resources report from the Director, FWS. Such reports may include but are not limited to:

(1) Information concerning results of periodic studies on problems relating to the impact of mineral exploration and exploitation on estuarine and coastal resources.

(2) Information which relates directly or indirectly to the assessment of potential environmental impact of the administration and supervision of mineral exploration and production on OCS lands by BLM or USGS.

(3) Information useful in the identification and designation of restricted use areas including, but not limited to, Marine Reserves, Marine or Estuarine Sanctuaries and National Wildlife Refuges and coastal units of the National Park System.

(b) During the period when tracts are evaluated for leasing, the manager of the appropriate OCS Office, BLM, shall obtain the views of the appropriate Regional or Area (Alaska) Director, FWS, concerning the potential effects of oil and gas development on biotic and other resources.

(c) In the writing of lease stipulations, BLM shall obtain the advice and participation of FWS, NPS, and USGS.

(d) BLM will give FWS the opportunity to review Notices of Lease Offer and to make written recommendations thereon, prior to their publication in the Federal Register.

(e) BLM, with the participation of FWS and in accordance with the August 1, 1974, MOU with USGS, will plan the alignment of pipelines which will extend between OCS and onshore locations. The FWS should prepare and submit reports to BLM concerning the potential effects on biotic resources of placement of pipelines along such alignments.

(f) The Area Oil and Gas Supervisors, USGS, will consult with and when appropriate receive recommendations from the responsible field representatives of FWS and NPS acting jointly, and BLM:

(1) Prior to issuance of draft OCS orders.

(2) Prior to granting rights of use or easements to lessees to construct and maintain artificial islands or fixed structures (including pipelines) on the OCS.

(3) Prior to approval of exploratory drilling plans and plans of development.

(4) Prior to approval of other major activities on the OCS.

(g) In implementing the consultative procedures described in Section 4f, FWS and NPS acting jointly, and BLM shall act as advisors on matters within their respective responsibilities and expertise and not duplicate USGS operational analyses conducted under the authorities in 30 CFR, Part 250. Further, in implementing these consultative procedures, the USGS will inform the appropriate representatives of FWS and NPS acting jointly, and BLM of major activities relevant to the OCS, either planned or for which authority has been requested. USGS shall defer approval of such activities for 5 working days to allow FWS and NPS acting jointly, and BLM to determine whether their expert advice is pertinent to such activities and to notify USGS of an intention to offer recommendations. If there is no response within 5

days, USGS will assume that there will be no recommendations. If USGS receives notice of forthcoming recommendations, the notifying agency will at the same time request documents and data that USGS has available and which are necessary for further evaluation. Arrangements may be made between the bureaus to facilitate receiving transfers of information. USGS shall defer approval of the activities until the recommendations have been received or until 20 working days have elapsed from the time the requested documents or data have been forwarded by USGS. Arrangements may be made, as necessary, for agreed upon dates of transmittal and receipt. In the absence of a request for documents or data, USGS shall defer approval of the activities until the recommendations have been received or until 20 working days have elapsed from the time the notice of forthcoming recommendations was received.

(h) BLM, with the participation and recommendations of FWS and GS, will design any biological sampling or monitoring plans that may be required in connection with special lease stipulations for the protection of biotic resources. Such plans will contain minimum survey and data collection requirements as may be necessary to comply with special lease stipulations. Any changes to such plans will be made only after consultation of the agencies and offices affected.

(i) NPS shall make recommendations to implement special lease stipulations on cultural resources.

(j) BLM and GS shall provide the NPS with information on cultural resources discovered during operational activities and on site survey anomalies which may indicate the presence of cultural resources.

Sec. 5 Committees.

(a) A committee will be formed at the headquarters level consisting of representatives from AS-PD&B, BLM, FWS, NPS, USGS, and the Solicitor's Office to serve as the formal mechanism for coordination and planning, implementing the provisions in Sections 1 to 4, and providing a forum for exchanging of views among the participants. The chairman of the committee will be the representative of AS-PD&B. Meetings will be scheduled as needed and convene at the call of the chairman. Provisions will be made for convening meetings at the call of any participating bureau or office.

(b) Field-level committees will be formed for Mid-Atlantic, North Atlantic, South Atlantic, Gulf of Mexico, Southern California, Alaska and, at the direction of the AS-PD&B, any other regions where OCS field operations are centered and will consist of representatives from the bureaus and offices named in Section 5(a). The field-level committees will serve as the formal field-level mechanism for coordination and planning, implementing the provisions in Sections 1 to 4, and providing a forum for exchanging of views among the participants. The chairmen of the field committees will be appointed by the top ranking field level officials of the involved bureaus and offices. The frequency and scope of meetings will be determined by major OCS activities requiring the coordinated views of the bureaus and offices. Provisions will be made for convening meetings at the call of any participant. For reasons of economy and convenience, the members of the committee may decide to confer by telephone rather than meet as a group.

(c) The committees described in this Section shall be established and operate in accordance with the provisions of 308 DM 4.

Sec. 6 Resolution of Disagreements.

If BLM, FWS, NPS and USGS disagree for good and sufficient reasons on any of the operational aspects detailed in Section 4, the matter in dispute will be resolved as follows:

(a) If it is a field level issue, it will first be considered together by the appropriate top ranking representatives of BLM, FWS, NPS and USGS. If the issue cannot be resolved satisfactorily in this manner, it will be referred for resolution to the concerned Directors at headquarters level.

(b) If it is a policy issue or one which is otherwise handled at headquarters level, the issues will be referred for resolution through the appropriate Assistant Secretaries to AS-PD&B.

Sec. 7 Effective Date

This Order amends Secretarial Order 2974 dated April 30, 1975 and is effective immediately. Its provisions shall remain in effect until the Order is amended, superseded or revoked, whichever occurs first. However, in the absence of the foregoing actions, the provisions of this Order shall terminate on December 31, 1977.

Appendix F

Summary of U.S. Coast Guard Regulations Concerning Offshore Structures as Hazards to Navigation

The pertinent regulations summarized below are found in the Code of Federal Regulations, No. 33, Navigation and Navigable Waters, Part 67, Subpart 67.20.

The varied depths of water and marine commerce traffic routes which exist in the waters over the Outer Continental Shelf, and in other waters, permit the classification of structures according to their location in such waters. The structures in the area seaward of the line of demarcation specified by the Commandant and published in the Federal Register are designated as Class "A". This designation includes OCS platforms.

General requirements for lights specify that structures having a horizontal dimension of over 15 m (50 ft.) on any one side or in diameter, shall be required to have an obstruction light on each corner, or 90° apart in the case of circular structures. Each light is to have a 360° lens. Where two or more obstruction lights are required by the size of the structure they must be in the same horizontal plane and not less than 6 m (20 ft.) above mean high water.

They shall be installed in a manner that will permit a mariner to hold sight of at least one of them until he is within 15 m (50 ft.) of the structure. Class "A" structure lights shall be white, powered from a reliable power source, and display a quick flash characteristic of approximately 60 flashes per minute. The lights shall be of sufficient candlepower to be visible at a distance of 9 km (5 naut. mi.) 90% of the nights of the year, and they shall be displayed at all times between sunset and sunrise local time, commencing at the time construction of the structure is begun.

The fog signal shall have a frequency range above 100 cycles and a loudness level of 55 phons and shall be sounded every 20 seconds (sound two seconds, silent 18 seconds). For Class "A" structures this signal shall have an audible range of not less than 3 km (2 mi.) (under no wind condition) in all directions from the structure it marks, whenever visibility is less than 8 km (5 mi.) in any direction.

Changes in these rules may be permitted upon approval of the District Commander when warranted by circumstances, such as proximity of structures.

Appendix G

Proposed OCS Operating Orders for the U.S. South Atlantic Region

/s/ THOMAS S. KLEPPE

GEOLOGICAL SURVEY

Oil and Gas Operations

EASTERN REGION OCS ORDERS

On July 12, 1976 (41 FR 28553), OCS Orders for the Mid-Atlantic Area were published. These OCS Orders provide requirements for oil and gas drilling activity on any oil and gas leases to be issued as a result of the lease sale scheduled to be held in September 1977. The following OCS Orders for the Mid-Atlantic Area were effective July 1, 1976.

Order No. 1 - "Marking of Wells, Platforms, and Structures"
Order No. 2 - "Drilling Procedures"
Order No. 3 - "Plugging and Abandonment of Wells"
Order No. 4 - "Suspensions and Determination of Well Producibility"
Order No. 5 - "Subsea Safety Devices"
Order No. 7 - "Pollution and Waste Disposal"
Order No. 12 - "Public Inspection of Records"

The current lease sales schedule shows a tentative lease sale to be held in the South Atlantic in September of 1977. The Geological Survey is in the process of developing final OCS Orders to cover drilling activities in this area should this lease sale be held.

Interested parties are requested to provide comments on the content of the South Atlantic OCS Orders. The newly issued Mid-Atlantic OCS Orders are being considered as draft OCS Orders for this Area. Commenters are requested to indicate operational changes that may be necessary due to different conditions to be encountered in the South Atlantic Area. For the purpose of these OCS Orders, the South Atlantic Area includes OCS lands from 37° N latitude south to Key West. Comments will be accepted until March 1, 1977, and should be sent to:

Acting Chief, Conservation Division
U.S. Geological Survey, National Center
Mail Stop 600, 12201 Sunrise Valley Drive
Reston, Virginia 22092

The U.S. Geological Survey has determined that this document does not contain a major proposal requiring preparation of an Inflation Impact Statement under Executive Order 11821 and OMB Circular A-107.

W. A. RADLINSKI
Acting Director

UNITED STATES DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY—CONSERVATION DIVISION
EASTERN AREA

PROPOSED SOUTH ATLANTIC OCS ORDER NO. 1

"IDENTIFICATION OF WELLS, PLATFORMS, STRUCTURES, AND SUBSEA OBJECTS"

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.37.

The operator shall comply with the following requirements. All departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. *Identification of Fixed Platforms or Structures.* Platforms and structures shall be identified at two diagonal corners by a sign with letters and figures not less than 30 centimetres (12 inches) in height with the following information: The name of lease operator, the area name shown on OCS Official Protraction Diagrams (or, where no name has been assigned, the Protraction Diagram number), the block number in which the platform or structure is located, and the platform or structure designation. The information shall be abbreviated as in the following example:

"The Blank Oil Company operates "C" platform on Block 999 of the Salisbury Area"

The identifying sign on the platform would indicate:

"BOC–SAL–999–C."

2. *Identification of Nonfixed Platforms or Structures.* Floating semi-submersible platforms, bottom-setting mobile rigs, and drilling ships shall be identified by one sign with letters and figures not less than 30 centimetres (12 inches) in height affixed to the derrick so as to be visible from off the vessel and containing the following information: The name of the lease operator, the area designation based on OCS Official Leasing Maps, the block number, the OCS lease number, and the well number.

3. *Identification of Wells.* The OCS lease and well number shall be painted on, or a sign affixed to, each singly completed well. In multiple completed wells each completion shall be individually identified at the well head. All identifying signs shall be maintained in a legible condition.

4. *Identification of Subsea Objects.* All subsea objects resulting from lease operations, and presenting a hazard to navigation or to deployment of commercial fishing devices, shall be identified with navigational markings. Such identification shall be in accordance with a design approved by the Supervisor and shall not be inconsistent with applicable U.S. Coast Guard regulations. These navigational markings shall be maintained on-sight and operable at all times so long as the obstruction remains.

/s/ Harry A. DuPont
Area Oil and Gas Supervisor

Approved:

Russell G. Wayland
Acting Chief, Conservation Division

UNITED STATES DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY—CONSERVATION DIVISION
EASTERN AREA

PROPOSED SOUTH ATLANTIC OCS ORDER NO. 2

DRILLING PROCEDURES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11. All exploratory and development wells drilled for oil and gas shall be drilled in accordance with 30 CFR 250.34, 250.41, 250.91, and the provisions of this Order which shall continue in effect until field drilling rules are issued. When sufficient geologic and engineering information is obtained through exploratory drilling, operators may make application or the Area Supervisor may require an application for the establishment of field drilling rules. After field drilling rules have been established by the Area Supervisor, development wells shall be drilled in accordance with such rules.

All wells drilled under the provisions of this Order shall have been included in an exploratory or development plan for the lease as required under 30 CFR 250.34. Each Application for Permit to Drill (Form 9–331C) shall include all information required under 30 CFR 250.91, and shall include a notation of any proposed departures from the requirements of this Order. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

The operator shall comply with the following requirements. All applications for approval under the provisions of this Order shall be submitted to the appropriate District Supervisor. References in this Order to approvals, determinations, or requirements are to those given or made by the Area Supervisor or his delegated representative.

1. *Drilling Platforms and Vessels*

A. All drilling platforms and drilling vessels shall be capable of withstanding the oceanographic and meteorological conditions for the proposed area of operations. The operator must furnish evidence of the fitness of the drilling platform or vessel to perform the planned drilling operation at the proposed drilling location. Applications for drilling from mobile drilling platforms and drilling vessels shall include the following:

(1) Design, drawings, equipment specifications, and performance data.

(2) Operational criteria and a critical operations plan as described in Section 8 of this Order.

(3) Environmental conditions expected.

(4) Current classification or certification of fitness with operational limitations.

B. Prior to commencing operations, all drilling platforms and drilling vessels shall be given a complete inspection by a representative of the U.S. Geological Survey to insure compliance with OCS Orders and regulations.

C. Operators shall collect and report oceanographic, meteorological, and performance data during the period of operations. The type of information and the method of collecting shall be set forth in the proposed plan of operations.

2. *Well Casing and Cementing*. All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.41(a)(1), and the Application for Permit to Drill shall include the casing design safety factors for collapse, tension, and burst. In cases where cement has filled the annular space back to the ocean floor, the cement may be washed out or displaced to a depth not exceeding 12 metres (40 feet) below the ocean floor to facilitate casing removal upon well abandonment. For the purpose of this Order, the several casing strings in order of normal installation are drive or structural, conductor, surface, intermediate, and production casing.

For the surface, intermediate, and production casing strings, if there are indications of improper cementing such as lost returns, cement

channeling, or mechanical failure of equipment, the operator shall recement or make the necessary repairs and run a temperature or cement bond log to verify that the casing has been adequately cemented.

The design criteria for all wells shall consider all pertinent factors for well control, including formation fracture gradients and pressures and casing setting depths. All casing, except drive pipe, shall conform to the specifications contained in "API Spec 5A—Thirty-second Edition, March 1973—Casing, Tubing, and Drill Pipe," as amended by supplement 2, March, 1975, or supplements thereto as approved by Area Supervisor, shall be new pipe or reconditioned used pipe that has been tested to insure that it will meet API specifications for new pipe.

A. *Drive or Structural Casing.* This casing shall be set by drilling, driving, or jetting to a minimum depth of 30 metres (100 feet) below the ocean floor or to such depth, approved by the Supervisor, required to support unconsolidated deposits and to provide hole stability for initial drilling operations. If this portion of the hole is drilled, the drilling fluid shall be of a type that is in compliance with the liquid disposal requirements of OCS Order No. 7, and a quantity of cement sufficient to fill the annular space back to the ocean floor shall be used.

B. *Conductor and Surface Casing.* Casing design and setting depths shall be based upon all engineering and geologic factors, including the presence or absence of hydrocarbons or other potential hazards and water depths.

(1) *Conductor Casing.* This casing shall be set at a depth in accordance with paragraph 2B(3) below. A quantity of cement sufficient to fill the annular space back to the ocean floor shall be used.

(2) *Surface Casing.* This casing shall be set at a depth in accordance with paragraph 2B(3) below and cemented in a manner necessary to protect all freshwater sands and provide well control until the next string of casing is set.

This casing shall be cemented with a quantity sufficient to fill the calculated annular space to at least 460 metres (1,500 feet) above the surface casing shoe and at least 60 metres (197 feet) inside the conductor casing or as approved by the District Supervisor. After drilling a maximum of 30 metres (100 feet) below the surface casing shoe, a pressure test shall be obtained to aid in determining a formation fracture gradient either by testing to formation leak-off or by testing to a predetermined equivalent mud weight. The results of this test and any subsequent tests of the formation shall be recorded on the driller's log and used to determine the depth and maximum mud weight to be used in drilling the intermediate hole.

(3) *Conductor and Surface Casing Setting Depths.* These strings of casing shall be set at the depth specified below, subject to approved variation to permit the casing to be set in a competent bed, or through formations determined desirable to be isolated from the well by pipe for safer drilling operations; provided, however, that the conductor casing shall be set immediately prior to drilling into formations known to contain oil or gas, or, if unknown, upon encountering such formations. These casing strings shall be run and cemented prior to drilling below the specified setting depths. For those wells which may encounter abnormal pressure or conditions and for the initial wells in an area, the District Supervisor may prescribe an additional casing string and the exact setting depths. Except as otherwise may be prescribed, conductor casing setting depths shall be between 90 metres (295 feet) and 300 metres (984 feet) (TVD below ocean floor), and surface casing setting depths shall be between 300 metres (984 feet) and 1,400 metres (4,592 feet) (TVD below ocean floor).

Engineering, geophysical, and geologic data used to substantiate the proposed setting depths of the conductor and surface casings (such as estimated fracture gradients, pore pressures, shallow hazards, etc.) shall be furnished with the Application for Permit to Drill.

C. *Intermediate Casing.* One or more strings of intermediate casing shall be set when required by anticipated abnormal pressure, mud weight, sediment, and other well conditions. The proposed setting depth for intermediate casing will be based on the pressure tests of the exposed formation immediately below the surface casing shoe or on subsequent pressure tests. If before reaching the proposed setting depth, the mud weight has been increased to within 0.06 kg/dm^3 (0.5 ppq) of the equivalent mud weight of the most recent pressure test of the formation below the surface casing shoe, the operator shall discontinue drilling and set an intermediate casing string.

A quantity of cement sufficient to cover and isolate all hydrocarbon zones and to isolate abnormal pressure intervals from normal pressure intervals shall be used. Sufficient cement shall be used to provide annular fill up to a minimum of 150 metres (492 feet) above the zones to be isolated or 150 metres (492

feet) above the casing shoe in cases where zonal coverage is not required. If a liner is used as an intermediate string, the cement shall be tested by a fluid entry or pressure test to determine whether a seal between the liner top and next larger string has been achieved. The test shall be recorded on the driller's log. When such liner is used as production casing, it shall be extended to the surface and cemented to avoid surface casing being used as production casing.

D. *Production Casing*. This string of casing shall be set before completing the well for production. It shall be cemented in a manner necessary to cover or isolate all zones which contain hydrocarbons, but in any case, a calculated volume sufficient to fill the annular space at least 150 metres (492 feet) above the uppermost producible hydrocarbon zone must be used. When a liner is used as production casing, the testing of the seal between the liner top and the next larger string shall be conducted as in the case of intermediate liners. The test shall be recorded on the driller's log.

E. *Pressure Testing of Casing*. Prior to drilling the plug after cementing, all casing strings, except the drive or structural casing, shall be pressure-tested as shown in the table below. The test pressure shall not exceed the internal yield pressure of the casing. The surface casing shall be tested with water in the top 30 metres (100 feet) of the casing. If the pressure declines more than 10 percent in 30 minutes, or if there is other indication of a leak, corrective measures shall be taken until a satisfactory test is obtained.

Casing	*Minimum Surface Pressure*
Conductor	1,400 kilopascals (kPa) (203 psi)
Surface	6,900 kPa (1,000 psi)
Intermediate	10,400 kPa (1,508 psi) or
Liner, and Production	5 kPa/m (0.22 psi/ft.), whichever is greater

After cementing any of the above strings, drilling shall not be commenced until a time lapse of eight hours under pressure for conductor casing string or 12 hours under pressure for all other strings. Cement is considered under pressure if one or more float valves are employed and shown to be holding the cement in place or when other means of holding pressure are used. All casing pressure tests shall be recorded on the driller's log.

3. *Directional Surveys*. Wells are considered vertical if inclination does not exceed three degrees from the vertical. Inclination surveys shall be obtained on all vertical wells at intervals not exceeding 150 metres (492 feet) during the normal course of drilling.

Wells are considered directional if inclination exceeds three degrees from the vertical. Directional surveys giving both inclination and azimuth shall be obtained on all directional wells at intervals not exceeding 150 metres (492 feet) during the normal course of drilling and at intervals not exceeding 30 metres (100 feet) in all angle change portions of the hole.

On both vertical and directional wells, directional surveys giving both inclination and azimuth shall be obtained at intervals not exceeding 150 metres (492 feet) prior to, or upon, setting surface or intermediate casing, liners, and total depth.

Composite directional surveys shall be filed with the District Supervisor. The interval shown will be from the bottom of conductor casing, or, in the absence of conductor casing, from the bottom of drive or structural casing to total depth. In calculating all surveys, a correction from true north to Universal Transverse Mercator-Grid north shall be made after making the magnetic to true north correction.

4. *Blowout Prevention Equipment*. Blowout preventers and related well-control equipment shall be installed, used, and tested in a manner necessary to insure well control. Prior to drilling below the drive pipe or structural casing and until drilling operations are completed, blowout prevention equipment shall be installed and maintained ready for use as follows:

A. General Requirements

(1) *Blowout Prevention Equipment*. Blowout prevention equipment shall consist of an annular and a specific number of ram-type preventers. (Subsea blowout-preventer stacks used with floating drilling vessels shall be equipped with one set of blind-shear rams). The pipe rams shall be of proper size to fit the pipe in use. The bore of all preventers and spools shall be of sufficient size to accommodate the largest equipment that is expected to be run into the casing below the preventers. The working pressure of any blowout preventer shall exceed the maximum anticipated surface pressure to which it may be subjected. Information submitted with the Application for Permit to Drill shall include the maximum anticipated surface pressure and the criteria used to determine this pressure. A fail safe design shall be incorporated into the blowout-prevention system and shall include dual control systems fail safe valving on critical lines and outlets. In addition, for subsea blowout-preventer stacks, a subsea accumulator system is required to provide fast closure of preventers and for cycling all critical functions in case of loss of connection to the surface.

All preventers shall be equipped with:

(a) A hydraulic actuating system that provides sufficient accumulator capacity to close all blowout prevention equipment units with a 50 percent operating fluid reserve at 8300 KPa (1,204 psi). A high pressure nitrogen or other accumulator back-up system shall be provided with sufficient capacity to close all blowout preventers and hold them closed. Locking devices shall be provided on the ram-type preventers.

(b) An operable remote blowout-preventer-control station shall be provided, in addition to the one on the drilling floor.

(c) A drilling spool with side outlets, if side outlets are not provided in the blowout preventer body, shall be installed to provide for a kill line and choke manifold. An auxiliary connection for an emergency kill or choke line shall be provided below any preventer that is in use and not located on the sea floor.

(d) A kill line with a master valve located next to the well. This valve shall not be used for normal opening or closing on flowing fluids. The kill line shall have at least one control valve in addition to the master valve.

(e) A choke manifold equipped with a hydraulic control valve, a master valve, three adjustable chokes of which one shall be a hydraulic adjustable choke, and an accurate pressure gauge. The choke manifold outlets shall be connected in such a manner that the returns may be directed to the mud system or other appropriate storage.

(f) A fill-up line.

(g) The annular type preventer shall be equipped with an alternate control to be used in case the primary controls fail.

(h) All valves, pipes, and fittings upstream of and including the choke manifold that can be exposed to pressure from the wellbore shall be of a pressure rating at least equal to that required of the blowout-prevention equipment.

(2) *Auxiliary Equipment.* The following auxiliary equipment shall also be provided:

(a) A top kelly cock shall be installed below the swivel, and an essentially full-opening kelly cock of such design that it can be run through blowout preventers shall be installed at the bottom of the kelly.

(b) An inside blowout preventer and an essentially full opening drill string safety valve in the open position shall be maintained on the rig floor at all times while drilling operations are being conducted. Valves shall be maintained on the rig floor to fit all pipe that is in the drill string. A safety valve shall be available on the rig floor assembled with the proper connection to fit the casing string that is being run in the hole.

B. *Drive Pipe or Structural Casing.* Before drilling below this string, at lease one remotely controlled, annular-type blowout preventer or pressure-rotating, pack-off-type head and equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed.

When the blowout-preventer system is on the ocean floor, the choke and kill lines or equivalent vent lines, equipped with necessary connections and fittings, shall be used for diversion. An annular preventer or pressure-rotating, pack-off-type head, equipped with suitable diversion lines as described above and installed on top of the marine riser, to permit the diversion of hydrocarbons and other fluids, may be utilized for diversion. The diverter system providing at least the equivalent of two 15 centimetre (6-inch) lines (or equivalent in internal cross-sectional area) and full-open or butterfly valves shall be installed in order to permit the full diversion of hydrocarbons and other fluids. The diverter system shall be equipped with automatic, remote-controlled valves which open prior to shutting in the well, with at least two lines venting in different directions to accomplish downwind diversion. A schematic diagram and operational procedure for the diverter system shall be submitted with the Application for Permit to Drill (Form 9–331C) to the District Supervisor for approval.

In drilling operations where a floating or semi-submersible type of drilling vessel is used and formation competency at the structural casing setting depth is not adequate to permit circulation of drilling fluids to the vessel while drilling conducter hole, a program which provides for safety in these operations shall be described and submitted to the District Supervisor for approval. This program shall include all known pertinent and relevant information, including seismic and geologic data, water depth, drilling-fluid hydrostatic pressure, schematic diagram from rotary table to proposed conductor casing seat, and contingency plan for moving off location. In all areas where shallow hazards or hydrocarbons are unknown, seismic data shall be obtained, and a small-diameter initial pilot hole from the bottom of drive or structural casing to proposed conductor casing seat shall be drilled to aid in determining the presence or absence of

these hazards. All seismic data shall be made available to the Supervisor, and an analysis of the geologic hazards shall be furnished with the Application for Permit to Drill.

C. *Conductor Casing*. Before drilling below this string, at least one remotely controlled, annular-type blowout preventer and equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed. A diverter system as described in paragraph 4B above shall be installed.

D. *Surface Casing*. Before drilling below this string, the blowout prevention equipment shall include a minimum of: (1) three remotely-controlled, hydraulically operated blowout preventers, including one equipped with pipe rams, one with blind rams, and one annular type: (Subsea blowout-preventer stacks used with floating drilling vessels shall be equipped with one set of blind-shear rams); (2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body; (3) a choke line and manifold; (4) a kill line separate from choke line; and (5) a fill-up line.

E. *Intermediate Casing*. Before drilling below this string, the blowout prevention equipment shall include a minimum of: (1) four remote-controlled, hydraulically operated blowout preventers with a working pressure which exceeds the maximum anticipated surface pressure, including at least two equipped with pipe rams, one with blind rams, and one annular type. (Subsea blowout-preventer stacks used with floating drilling vessels shall be equipped with one set of blind-shear rams); (2) a drilling spool with side outlets, if side outlets are not provided in the blowout preventer body; (3) a choke line and manifold; (4) a kill line separate from choke line; and (5) a fillup line.

F. *Testing*.

(1) *Pressure Test*. Ram-type blowout preventers and related control equipment shall be tested to the rated working pressure of the stack assembly, or at the working pressure of the casing, whichever is the lesser. Annular-type preventers shall be tested to 70 percent of these pressure requirements. They shall be tested: (a) when installed, (b) before drilling out after each string of casing is set, (c) not less than once each week while conducting drilling operations, and (d) following repairs that require disconnecting a pressure seal in the assembly.

(2) *Actuation*. While drill pipe is in use, the ram-type blowout preventers equipped with pipe rams shall be actuated at least once each day. If a tapered drill string is in use, the smaller size rams shall be actuated on the appropriate size pipe, once each trip. The blind rams shall be actuated while out of the hole once each trip. Accumulators or accumulators and pumps shall maintain a pressure capacity reserve at all times to provide for repeated operation of hydraulic preventers. An operable remote blowout-preventer-control station shall be provided in addition to the one on the drilling floor. Each control station will be tested for proper operation once each day when the pipe is out of the hole.

Each control system shall alternately be tested to ensure proper functioning. If either system is not functional, further drilling operations shall be suspended until that system becomes operable.

(3) *Drills*. A blowout-prevention drill shall be conducted weekly for each drilling crew to insure that all equipment is operational and that crews are properly trained to carry out emergency duties.

(4) *Records*. All blowout-preventer tests and crew drills shall be recorded on the driller's log.

(5) *Mud Program*. The characteristics, use, and testing of drilling mud and the conduct of related drilling procedures shall be such as are necessary to prevent the blowout of any well. Quantities of mud materials sufficient to insure well control shall be maintained readily accessible for use at all times.

A. *Mud Control*. Before starting out of the hole with drill pipe, the mud shall be properly conditioned. Proper conditioning requires either circulation with the drill pipe just off bottom to the extent that the annular volume is displaced, or proper documentation in the driller's log prior to pulling the drill pipe that: (1) there was no indication of influx of formation fluids prior to starting to pull the drill pipe from the hole, (2) the weight of the returning mud is not less than the weight of the mud entering the hole, and (3) other mud properties recorded on the daily drilling log are within the specified ranges at the stage of drilling the hole to perform their required functions. In those cases when the hole is circulated, the driller's log shall be so noted.

When coming out of the hole with drill pipe, the annulus shall be filled with mud before the mud level drops 30 metres (100 feet). A mechanical device for measuring the amount of mud required to fill the hole shall be utilized, and any time there is an indication of swabbing, or influx of formation fluids, the necessary safety devices and action shall be employed to control the well. The mud shall

not be circulated and conditioned, except on or near bottom, unless well conditions prevent running the drill pipe back to bottom. The mud in the hole shall be circulated or reverse-circulated prior to pulling drill-stem test tools from the hole.

The hole shall be filled by accurately measured volumes of mud. The number of stands of drill pipe and drill collars that may be pulled between the times of filling the hole shall be calculated and posted. The number of barrels and pump strokes required to fill the hole for this designated number of stands of drill pipe and drill collars shall be posted. For each casing string, the maximum pressure which may be applied to the blowout preventer before controlling excess pressure by bleeding through the choke shall be posted near the driller. Drill pipe pressure shall be monitored during the bleeding procedure for well control.

An operable degasser shall be installed in the mud system prior to the commencement of drilling operations and shall be maintained for use throughout the drilling and completion of the well.

B. *Mud Test Equipment*. Mud test equipment shall be maintained on the drilling rig at all times, and mud tests shall be performed once each tour, or more frequently as conditions warrant. Such tests shall be conducted in accordance with procedures outlined in API RP 13B, "Recommended Practice for Standard Procedure for Testing Drilling Fluids," Sixth Edition, April 1976, or subsequent revisions as approved by the Supervisor, and the results recorded and maintained at the drill site. The following mud-system monitoring equipment shall be installed (with derrick floor indicators) and used at the point in the drilling operation when mud returns are established and throughout subsequent drilling operations:

(1) Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator shall include a visual and audio warning device.

(2) Mud volume measuring device for accurately determining mud volumes required to fill the hole on trips.

(3) Mud return indicator to determine that returns essentially equal the pump discharge rate.

(4) Gas-detecting equipment to monitor the drilling mud returns.

C. *Mud Quantities*. The operator shall state in the Application for Permit to Drill the minimum quantities of mud material, including weighting material, to be maintained at the drill site for emergency use. This quantity shall not be less than the amount necessary to make a mud volume equal to twice the calculated capacity of the active down hole and surface mud system. The minimum quantity of weighting material to be maintained at the drill site shall be sufficient to overcome the highest anticipated formation pressure with the mud weight at least one pound per gallon greater than the weight required to overcome such formation pressure. Daily inventories of mud materials, including weighting material, shall be recorded and maintained at the drill site. Drilling operations shall be suspended in the absence of approved minimum quantities of mud materials for emergency use.

6. *Supervision, Surveillance, and Training*.

A. *Supervision*. A representative of the operator shall provide, on site, supervision of drilling operations on a 24-hour basis.

B. *Surveillance*. From the time drilling operations are initiated and until the well is completed or abandoned, a member of the drilling crew or the toolpusher shall maintain rig floor surveillance continuously, unless the well is secured with blowout preventors or cement plugs.

C. *Training*. Company and drilling contractor supervisory personnel including drillers shall be trained in and qualified for present-day well control. Records of such training and qualification shall be maintained at the drill site. Training shall include but is not limited to:

(1) Abnormal pressure detection methods.

(2) Well-control methods and procedures.

The operator shall additionally require well-control training for drillers in addition to the required weekly blowout prevention drills. Written verification of compliance with these provisions shall be filed with the Supervisor. As standards for training are developed for all members of the drilling crew, they will be incorporated into this Order. Compliance shall be considered a prerequisite to approval of any drilling operation.

7. *Hydrogen Sulfide*. When drilling operations are undertaken to penetrate reservoirs known or expected to contain hydrogen sulfide (H_2S), or, if unknown upon encountering H_2S, the preventive measures and operating practices set forth in U.S. Geological Survey Outercontinental Shelf Standard No. 1, (GSS–OCS–1), "Safety Requirements for Drilling Operations in a Hydrogen Sulfide Environment," February 1976, shall be followed.

8. *Critical Operations and Curtailment Plans.* Certain operations performed in drilling are more critical than others with respect to well control, fire, explosion, oil spills, and other discharge or emissions. These operations may occur during drilling, running casing, logging, drill-stem testing, well completion, or wire-line operations.

Each operator shall file with the Supervisor for approval of a Critical Operations and Curtailment Plan for the lease, which shall contain:

A. A list or description of the critical drilling operations that are or are likely to be conducted on the lease. Such list or description shall specify the operations to be ceased, limited, or not to be commenced under given circumstances or conditions. The list shall include operations such as:

(1) Drilling in close proximity to another producing well.

(2) Drill-stem testing.

(3) Running and cementing casing.

(4) Cutting and recovering casing.

(5) Logging or wireline operations.

(6) Well-completion operations.

(7) Moving the drilling vessel off location in an emergency; repositioning the vessel on location; and reestablishing entry into the well.

3. A list or description of circumstances or conditions under which such critical operations shall be curtailed. This list or description shall be developed from all the factors and conditions relating to the conduct of operations on the lease, and shall consider but necessarily not be limited to the following:

(1) Whether the drilling operations are to be conducted from mobile or fixed platforms.

(2) The availability and capability of containment and cleanup equipment.

(3) Abnormal or unusual characteristics expected to be encountered during drilling operations.

(4) Spill control system response time.

(5) Known or anticipated meteorological or oceanographical conditions.

(6) Availability of personnel and equipment for the particular operation to be conducted.

(7) Other factors peculiar to the particular lease under consideration.

C. When any such circumstance or condition listed or described in the plan occurs or other operational limits are encountered, the operator shall notify the Supervisor and shall curtail the critical operations as set forth under A above. In the conduct of the critical operations, full consideration shall be given to pertinent factors such as supply of well control materials, subsurface conditions, inventory of spill-containment equipment, weather conditions, particular esthetic conditions, fire hazards, available transportation equipment spill-control response time, and nature of work planned.

D. Any deviations in the plan shall require prior approval by the Supervisor except in case of an emergency in which event the Supervisor shall be notified as soon as possible.

E. The operator shall review the plan at least annually. Notification of the review and any amendments or modifications to the plan shall be filed with the Supervisor.

/s/ Harry A. DuPont
Area Oil and Gas Supervisor

Approved:

Russell G. Wayland
Chief, Conservation Division

UNITED STATES DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY—CONSERVATION DIVISION
EASTERN AREA

PROPOSED SOUTH ATLANTIC OCS ORDER NO. 3

PLUGGING AND ABANDONMENT OF WELLS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.15. The operator shall comply with the following minimum plugging and abandonment procedures which have general application to all wells drilled for oil and gas. Plugging and abandonment operations must not be commenced prior to obtaining approval from an authorized representative of the Geological Survey. Oral approvals shall be in accordance with 30 CFR 250.13. All departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. *Permanent Abandonment.*

A. *Isolation in Uncased Hole.* In uncased portions of wells, cement plugs shall be spaced to extend 30 meters (100 feet) below the bottom to 30 meters (100 feet) above the top of any oil, gas, and fresh water zones so as to isolate them in the strata in which they are found and to prevent them from escaping into other strata. Additional cement plugs may be required to protect other minerals, or to prevent migration of fluids in the well bore. No more than 762 meters (2,500 feet) of uncased hole shall be left without a cement plug of at least 30 meters (100 feet) in length in wells requiring a mud weight in excess of 1.44 kg/decimeters (12.0 ppg) for control.

B. *Isolation of Open Hole.* Where there is open hole (uncased and open into the casing string above) below the casing, a cement plug shall be placed in the deepest casing string by (1) or (2) below, or in the event lost circulation conditions exist or are anticipated, the plug may be placed in accordance with (3) below:

(1) A cement plug placed by displacement method so as to extend a minimum of 30 meters (100 feet) above and 30 meters (100 feet) below the casing shoe.

(2) A cement retainer with effective back pressure control set not less than 15 meters (50 feet), nor more than 30 meters (100 feet), above the casing shoe with a cement plug calculated to extend at least 30 meters (100 feet) below the casing shoe and 15 meters (50 feet) above the retainer.

(3) A permanent type bridge plug set within 46 meters (150 feet) above the casing shoe with 15 meters (50 feet) of cement on top of the bridge plug. This plug shall be tested prior to placing subsequent plugs.

C. *Plugging or Isolating Perforated Intervals.* A cement plug shall be placed opposite all open perforations (perforations not squeezed with cement) extending a minimum of 30 meters (100 feet) above and 30 meters (100 feet) below the perforated interval or down to a casing plug, whichever is less. In lieu of the cement plug, the following two methods are acceptable, provided the perforations are isolated from the hole below:

(1) A cement retainer with effective back pressure control set not less than 15 meters (50 feet) nor more than 30 meters (100 feet) above the top of perforated interval with a cement plug calculated to extend at least 30 meters (100 feet) below the bottom of the perforated interval and 15 meters (50 feet) above the retainer.

(2) A permanent type bridge plug set within 46 meters (150 feet) above the top of the perforated interval with 15 meters (50 feet) of cement on top of the bridge plug.

D. *Plugging of Casing Stubs.* If casing is cut and recovered, a cement plug 61 meters (200 feet) in length shall be placed to extend 30 meters (100 feet) above and 30 meters (100 feet) below the stub. A retainer may be used in setting the required plug.

E. *Plugging of Annular Space*. No annular space that extends to the ocean floor shall be left open to drilled hole below. If this condition exists, the annulus shall be plugged with cement.

F. *Surface Plug Requirement*. A cement plug of at least 46 meters (150 feet), with the top of the plug 46 meters (150 feet) or less below the ocean floor, shall be placed in the smallest string of casing which extends to the surface.

G. *Testing of Plugs*. The setting and location of the first plug below the top 46-meter (150-foot) plug, will be verified by either (1) placing a minimum pipe weight of 6,800 kilograms (15,000 pounds) on the plug, or where this plug is placed utilizing a cement retainer or bridge plug, it is only necessary that the setting of the retainer or bridge plug be verified by placing at least 6,800 kilograms (15,000 pounds) on it prior to placing cement on top, or (2) testing with a minimum pump pressure of 6,894 kPA (1,000 psi) with no more than a 10 percent pressure drop during a 15-minute period.

H. *Mud*. Each of the respective intervals of the hole between the various plugs shall be filled with mud fluid of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling such interval.

I. *Clearance of Location*. All casing and piling shall be severed and removed to that depth below the ocean floor approved by the area Supervisor after a review of data on the ocean bottom conditions. The operator shall verify that the location has been cleared of all obstructions.

2. *Temporary Abandonment*. Any drilling well which is to be temporarily abandoned shall be mudded and cemented as required for permanent abandonment except for requirements F and I of section 1 above. When casing extends above the ocean floor, a mechanical bridge plug (retrievable or permanent) shall be set in the casing between 4.6 and 61.0 meters (15 and 200 feet) below the ocean floor.

/s/ Harry A. DuPont
Area Oil and Gas Supervisor

Approved:

/s/ Russell G. Wayland
Chief, Conservation Division

UNITED STATES DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY—CONSERVATION DIVISION
EASTERN AREA

PROPOSED SOUTH ATLANTIC OCS ORDER NO. 4

SUSPENSIONS AND DETERMINATION OF WELL PRODUCIBILITY

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.12(d)(1). An OCS lease provides for extension beyond its primary term for as long as oil or gas may be produced from the lease in paying quantities. The term "paying quantities" as used herein means production in quantities sufficient to yield a return in excess of operating costs. An OCS lease may be maintained beyond the primary term, in the absence of actual production, when a suspension of production has been approved. All applications for suspension of production for an initial period should be submitted prior to the expiration of the term of a lease. The Area Supervisor may approve a suspension of production provided at least one well has been drilled on the lease and determined to be capable of producing in paying quantities. The temporary or permanent abandonment of a well will not preclude approval of a suspension of production as provided in 30 CFR 250.12(d)(1). All departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

To provide data necessary to determine that a well may be capable of producing in paying quantities, the following are minimum requirements:

1. *Oil Wells.* A production test of at least two hours duration, following stabilization of flow.
2. *Gas Wells.* A deliverability test of at least two hours duration, following stabilization of flow, or a four-point back-pressure test.
3. *Well Data.* All pertinent engineering, geologic, and economic data shall be submitted to the District Supervisor and will be considered in determining whether or not a well is capable of being produced in paying quantities.
4. *Witnessing and Results.* All tests must be witnessed by an authorized representative of the Geological Survey. Test data accompanied by operator's affidavit, or third-party test data, may be accepted in lieu of a witnessed test provided prior approval is obtained from the District Supervisor.

/s/ Harry A. DuPont
Area Oil and Gas Supervisor

/s/ Russell G. Wayland
Chief, Conservation Division

UNITED STATES DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY—CONSERVATION DIVISION
EASTERN AREA

PROPOSED SOUTH ATLANTIC OCS ORDER NO. 5

SUBSURFACE SAFETY DEVICES

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.41(b). The operator shall comply with the following requirements. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b). All applications for approval under the provisions of this Order shall be submitted to the District Supervisor. Reference in this Order to approvals, determinations, or requirements are to those given or made by the Area Supervisor or his delegated representative.

1. *Installation.* All tubing installations open to hydrocarbon-bearing zones shall be equipped with a surface-controlled subsurface safety device. The surface controls may be located onsite or remotely. The device is to be installed at a depth of 30 metres (100 feet) or more below the ocean floor unless, after application and justification, the well is determined to be incapable of flowing. These installations shall be made within two days after stabilized production is established. The well shall not be left unattended while open to production before a subsurface safety device is installed.

A. *Shut-in Wells.* A tubing plug shall be installed in lieu of, or in addition to, other subsurface safety devices if a well has been shut in for a period of six months. Such plugs shall be set at a depth of 30 metres (100 feet) or more below the ocean floor and shall be of the pump-through type. All wells perforated and completed, but not placed on production, shall be equipped with a subsurface safety device or tubing plug within two days after completion.

B. *Injection Wells.* Surface controlled subsurface safety devices shall be installed in all injection wells unless, after application and justification, it is determined that the well is incapable of flowing which condition shall be verified annually.

2. *Design, Testing, and Inspection.* Subsurface safety devices shall be designed, adjusted, installed, and maintained to insure reliable operation. During testing and inspection procedures, the well shall not be left unattended while open to production unless a properly operating subsurface safety device has been installed in the well.

A. *Surface-Controlled Subsurface Safety Devices.*

(1) *Quality Assurance and Performance.* The operator shall use subsurface safety devices that comply with the minimum standards set forth in "API Spec 14 A, First Edition, October 1973, Subsurface Safety Valves," as amended by supplement 2, February, 1976 or supplements thereto as approved by the Area Supervisor, for quality assurance including design, material, and functional test requirements, and for verification of independent party performance testing and manufacturer functional testing of such valves.

(2) *Installation and Testing.* The operator shall comply with the minimum recommended practices set forth in "API RP 14 B, First Edition, October 1973, Design, Installation, and Operation of Subsurface Safety Valve Systems," or supplements thereto as approved by the Area Supervisor, which contain procedures for design calculations, safe installation, and operating and testing. Each surface-controlled subsurface safety device installed in a well shall be tested in place for proper operation when installed, or reinstalled, at least monthly for the next six months and quarterly thereafter. If the device does not operate properly, it shall be promptly removed, repaired, and reinstalled or replaced and tested to insure proper operation.

B. *Tubing Plugs.* A shut-in well equipped with a tubing plug shall be inspected for leakage by opening the well to possible flow at intervals not exceeding six months. If sustained liquid flow exceeds 400 cm^3/min (.014 ft^3/min) or gas flow exceeds 425 dm^3/min (15 ft^3/min), the plug shall be promptly removed, repaired, and reinstalled or an additional tubing plug installed to prevent leakage.

3. *Temporary Removal.* Each wireline or pumpdown-retrievable subsurface safety device may be removed, without further authorization or notice, for a routine operation which does not require approval of a Sundry Notice and Report on Wells (Form 9–331) for a period not to exceed fifteen days. The well shall be clearly identified as being without a subsurface safety device and shall not be left unattended while open to production. The provisions of this paragraph are not applicable to the testing and inspection procedures specified in section 2 (Design, Testing, and Inspection) above.

4. *Additional Protective Equipment.* All tubing installations in which a wireline or pumpdown-retrievable subsurface safety device is to be installed shall be equipped with a landing nipple, with flow couplings or other protective equipment above and below, to provide for setting of the subsurface safety device. All wells in which a subsurface safety device or tubing plug is installed shall have the tubing-casing annulus packed off above the uppermost open casing perforations, and at least 30 metres (100 feet) below the measured top of cement on the production string or the intermediate string. The control system for all surface-controlled subsurface safety devices shall be an integral part of the platform shut-in system.

5. *Departures.* All departure applications will be considered for approval pursuant to 30 CFR 250.12(b) and the requirements of this Order. All applications for departures shall include a detailed statement of the well conditions, efforts made to overcome any difficulties, and proposed alternate safety measures.

6. *Emergency Action.* All tubing installations open to hydrocarbon-bearing zones and not equipped with a subsurface safety device as permitted by this Order shall be clearly identified as not being so equipped, and a subsurface safety device or tubing plug shall be available at the field location. In the event of an emergency, such device or plug shall be promptly installed, due consideration being given to personnel safety.

7. *Records.* The operator shall maintain the following records for a minimum period of one year for each subsurface safety devices and tubing plug installed, and these records shall be available to any authorized representative of the Geological Survey.

A. *Field Records.* Individual well records shall be maintained at or near the field and shall include, as a minimum, the following information:

(1) A record which will give design and other information; i.e., make, model, type, spacers, bean and spring size, pressure, etc.

(2) Verification of assembly by a qualified person in charge of installing the device and installation date.

(3) Verification of setting depth and all operational tests as required in this Order.

(4) Removal date, reason for removal, and reinstallation date.

(5) A record of all modifications of design in the field.

(6) All mechanical failures or malfunctions, including sand cutting, of such devices, with notation as to cause or probable cause.

(7) Verification that failure report was submitted.

B. *Other Records.* The following records, as a minimum shall be maintained at the operator's office:

(1) Verified design information of subsurface safety devices for the individual well.

(2) Verification of assembly and installation according to design information.

(3) All failure reports.

(4) All laboratory analysis reports of failed or damaged parts.

(5) Quarterly failure-analysis report.

8. *Reports.* Well completion reports (Form 9–330) and any subsequent reports of workover (Form 9–331) shall include the type and the depth of the subsurface safety devices and tubing plugs installed.

To establish a failure-reporting and corrective-action program as a basis for reliability and quality control, each operator shall submit a quarterly failure-analysis report to the Area Supervisor, identifying mechanical failures by lease and well, make and model, cause or probable cause of failure, and action taken to correct the failure. The report shall be submitted within 30 days following the periods ending December 31, March 31, June 30, and September 30 of each year.

/s/ HARRY A. DUPONT
Area Oil and Gas Supervisor

APPROVED:

/s/ RUSSELL G. WAYLAND
Chief, Conservation Division

UNITED STATES DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY—CONSERVATION DIVISION
EASTERN AREA

PROPOSED SOUTH ATLANTIC OCS ORDER NO. 7

POLLUTION AND WASTE DISPOSAL

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.43. The operator shall comply with the following requirements. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. *Pollution Prevention.* In the conduct of all oil and gas operations, the operator shall prevent pollution of the ocean. Furthermore, the disposal of waste materials into the ocean shall not create conditions which will adversely affect the públic health, life or property, aquatic life or wildlife, recreation, navigation, or other uses of the ocean.

A. *Liquid Disposal.*

(1) Drilling mud containing free oil shall not be disposed of into the ocean.

(2) The operator shall submit with the Application for Permit to Drill (Form 9–331C) a detailed list of drilling mud components including the common chemical or chemical trade name of each component, and a list of the drilling mud additives anticipated for use in meeting special drilling requirements. Disposal of drilling mud shall be by methods which will minimize the adverse effects to marine life. These methods shall not be inconsistent with applicable Federal Regulations. Approval of drilling mud disposal procedures will be site specific and on a case-by-case basis.

(3) Curbs, gutters, and drains on platforms and structures shall be installed and maintained in accordance with the provisions of OCS Order No. 8.

(4) Discharges from fixed structures including sanitary waste, produced water, and deck drainage are subject to Environmental Protection Agency permitting procedures pursuant to the Federal Water Pollution Control Act as amended.

B. *Solid Waste Disposal.*

(1) Drill cuttings, sand, and other solids containing oil shall not be disposed of into the ocean unless all of the free oil has been removed.

(2) Mud containers and other similar solid waste materials shall be incinerated or transported to shore for disposal in accordance with Federal, State, or local requirements.

2. *Personnel, Inspections and Reports.*

A. *Personnel.* The operator's personnel shall be thoroughly instructed in the techniques of equipment maintenance and operation for the prevention of pollution. Nonoperator personnel shall be informed in writing, prior to executing contracts, of the operator's obligations to prevent pollution.

B. *Pollution Inspection Schedules.* Operators shall inspect their facilities as follows:

(1) Manned facilities shall be inspected daily.

(2) Unattended facilities, including those equipped with remote control and monitoring systems, shall be inspected at frequent intervals. The District Supervisor may prescribe the frequency of inspections for these facilities.

(3) All production facilities, such as separators, tanks, treaters, and other equipment shall be designed to prevent pollution. Maintenance or repairs necessary to prevent pollution of the ocean shall be undertaken immediately.

C. *Pollution Reports.* All pollution reports required shall be submitted on Form 9–1880, entitled Pollution Report.

(1) All spills of oil and liquid pollutants shall be recorded showing the cause, size of spill, and action taken, and the record shall be maintained and available for inspection by the District Supervisor. All spills of less than 2.5 cubic metres (15 barrels) shall be reported orally to the District

Supervisor within 12 hours and shall be confirmed in writing.

(2) All spills of oil and liquid pollutants of 2.5 to 8 cubic metres (15 to 50 barrels) shall be reported orally to the District Supervisor within four (4) hours and shall be confirmed in writing.

(3) All spills of oil and liquid pollutants of more than 8 cubic metres (50 barrels) shall be reported orally without delay to the District Supervisor and the Coast Guard. All oral reports shall be confirmed in writing. The District Supervisor shall notify the Governor, or his designee, of all such spills without delay.

(4) Operators shall notify each other upon observation of equipment malfunction or pollution resulting from another's operation.

3. *Pollution Control Equipment and Oil Spill Contingency Plan.*

A. *Equipment.* Standby pollution control equipment and materials shall be maintained by, or shall be available to, each operator at an offshore or onshore location. This shall include containment booms, skimming apparatus, cleanup materials and chemical agents, and shall be available prior to the commencement of operations. No chemicals shall be used without prior approval of the Area Supervisor. The equipment and materials shall be inspected monthly and maintained in good condition for use. The results of the inspections shall be recorded and maintained at the site.

B. *Oil Spill Contingency Plan.* The operator shall submit an oil spill contingency plan for approval by the Area Supervisor before consideration can be given to approval of an application for permit to conduct operations. This plan shall contain the following:

(1) Provisions to assure that full resource capability is known and can be committed during an oil discharge situation including the identification and inventory of applicable equipment, materials, and supplies which are available locally and regionally, both committed and uncommitted, and the time required for deployment.

(2) Provisions for varying degrees of response effort depending on the severity of the oil discharge.

(3) Establishment of notification procedures for the purpose of early detection and timely notification of an oil discharge including a current list of names, telephone numbers, and addresses of the responsible persons and alternates on call to receive notification of an oil discharge, as well as the names, telephone number, and addresses of regulatory organizations and agencies to be notified when an oil discharge is discovered.

(4) Provisions for well defined and specific actions to be taken after discovery and notification of an oil discharge including:

(a) Specification of an oil discharge response operating team consisting of trained, prepared and available operating personnel.

(b) Predesignation of an oil discharge response coordinator who is charged with the responsibility and delegated commensurate authority for directing and coordinating response operations.

(c) A preplanned location for an oil discharge response operations center and a reliable communications system for directing the coordinated overall response operations.

4. *Spill Control and Removal.* Immediate corrective action shall be taken in all cases where pollution has occurred. Corrective action taken under the Oil Spill Contingency Plan shall be subject to modification when directed by the Area Supervisor. The primary jurisdiction to require corrective action to abate the source of pollution and to enforce the subsequent cleanup by the lessee or operator shall remain with the Area Supervisor pursuant to the provisions of this Order and the memorandum of understanding between the Department of Transportation (U.S. Coast Guard) and the Department of the Interior (U.S. Geological Survey) dated August 16, 1971.

Annual Contingency Plan Assessment. Annual contingency plan assessments will be conducted in conjunction with the Plan of Development review. Upon request of the Area Supervisor, revised contingency plans reflecting changes in personnel, equipment, and methods shall be submitted.

/s/ Harry A. DuPont
Area Oil and Gas Supervisor

Approved:

/s/ Russell G. Wayland
Chief, Conservation Division

UNITED STATES DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY—CONSERVATION DIVISION
EASTERN AREA

PROPOSED SOUTH ATLANTIC OCS ORDER NO. 12

PUBLIC INSPECTION OF RECORDS

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.97 and 43 CFR Part 2. Requests for information made under the Freedom of Information Act, 5 U.S.C. sec. 552, will be governed by the provisions of 43 CFR Part 2 (40 F.R. 7304, February 19, 1975). Section 2.13 of 43 CFR says:

It is the policy of the Department of the Interior to make the records of the Department available to the public to the greatest extent possible, in keeping with the spirit of the Freedom of Information Act.

Section 2.15(c) of 43 CFR says:

A request for a record may be denied only if it is determined that (1) the record is exempt from disclosure (under the Freedom of Information Act) and (2) that withholding of the record is required by statute or Executive Order or supported by sound grounds.

The operator shall comply with the following requirements. All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

1. *Availability of Records*. It has been determined that certain records pertaining to leases and wells in the Outer Continental Shelf and submitted under 30 CFR 250 shall be made available for public inspection, as specified below, in the Area office. Certain other portions of these records have been determined to be exempt from disclosure. The reason for these exemptions is discussed in Section 4 of this Order.

A. *Form 9–152—Monthly Report of Operations*. All information contained on this form shall be available except the information required in the Remarks column.

B. *Form 9–330—Well Completion or Recompletion Report and Log*.

(1) Prior to commencement of production, all information contained on this form shall be available, except Item 1a, Type of Well; Item 4, Location of Well, at top production interval reported below: Item 22, if Multiple Completion, How many; Item 24, Producing Interval; Item 26, Type Electric and Other Logs Run; Item 28, Casing Record; Item 29, Liner Record; Item 30, Tubing Record; Item 31, Perforation Record; Item 32, Acid, Shot, Fracture, Cement Squeeze, etc.; Item 33, Production; Item 37, Summary of Porous Zones; and Item 38, Geologic Markers.

(2) After commencement of production, all information shall be available, except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers.

(3) If production has not commenced after an elapsed time of five years from the date of filing Form 9-330 as required in 30 CFR 250.38(b), all information contained on this form shall be available, except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers. Within 90 days prior to the end of the 5-year period, the lessee or operator shall file a Form 9-330 containing all information requested on the form, except Item 37, Summary of Porous Zones; and Item 38, Geologic Markers, to be made available for public inspection. Objections to the release of such information may be submitted with the completed Form 9-330.

C. *Form 9–331—Sundry Notices and Report on Wells*.

(1) When used as a "Notice of Intention to" conduct operations, all information contained on this form shall be available, except Item 4, Location of Well, at top production interval; and Item 17, Describe Proposed or Completed Operations.

(2) When used as a "Subsequent Report of" operations, and after commencement of

production, all information contained on this form shall be available, except information under Item 17 as to subsurface locations and measured and true vertical depths for all markers and zones not placed on production.

D. *Form 9–331C—Application for Permit to Drill, Deepen or Plug Back.* All information contained on this form, and location plat attached thereto, shall be available except Item 4, Location of Well at Proposed Production Zone; and Item 23, Proposed Casing and Cementing Production Program.

E. *Form 9–1869—qarterly Oil Well Test Report.* All information contained on this form shall be available.

F. *Form 9–1870—Semi-Annual Gas Well Test Report.* All information contained on this form shall be available.

G. *Multi-point Back Pressure Test Report.* All information contained on this form used to report the results of required multi-point back pressure test of gas wells shall be available.

H. *Sales of Lease Production.* Information contained on monthly Geological Survey computer printout showing sales volumes, value, and royalty of production of oil, condensate, gas and liquid products, by lease, shall be made available.

2. *Filing of Reports.* All reports on Forms 9–152, 9–330, 9–331, 9–331C, 9–1869, 9–1870, and the forms used to report the results of multi-point back pressure tests, shall be filed in accordance with the following: All reports submitted on these forms shall include a copy with the words "Public Information" shown on the lower right-hand corner. All items on the form not marked "Public Information" shall be completed in full; and such forms, and all attachments thereto, shall not be available for public inspection. The copy marked "Public Information" shall be completed in full, except that the items described in 1(A), (B), (C), and (D) above, and the attachments relating to such items, may be excluded. The words "Public Information" shall be shown on the lower right-hand corner of this set. This copy of the form shall be made available for public inspection.

3. *Availability of Inspection Records.* All accident investigation reports, pollution incident reports, facilities inspection data, and records of enforcement actions are also available for public inspection.

4. *Information Exempt from Public Inspection.* It has been determined that certain information as discussed in paragraphs 1.A, 1.B, 1.C, 1.D, and 2 of this Order is exempt from disclosure under exemption 9 of the Freedom of Information Act (5 U.S.C. 552(b)(9)). This information has been determined to qualify as "geological and geophysical information and data including maps concerning wells."

/s/ Harry A. DuPont
Area Oil and Gas Supervisor

Approved:

/s/ Russell G. Wayland
Chief, Conservation Division

UNITED STATES DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

Outer Continental Shelf Oil and Gas Operations

OCS ORDER NO. 15

Information Concerning Development Plans

Notice is hereby given that, pursuant to 30 CFR 250.11 and in accordance with the revision of 30 CFR 250.34, draft OCS Order 15, "Submittal of Information Concerning Development Plans to Coastal States" is proposed as set forth below.

The Federal Register publication, of November 4, 1975 (40 FR 51199), setting forth the revisions of 30 CFR 250.34 announced the intent to draft an OCS Order to implement the provisions of this revised regulation. OCS Order 15 is proposed for the purpose of defining more specifically the content and timing of information to be provided by lessees and operators to the States.

Interested persons may submit written comments and suggestions on the proposed Order to the Chief of the Conservation Division, U.S. Geological Survey, National Center, 12201 Sunrise Valley Drive, Reston, Virginia 22092, on or before January 1, 1977.

Pursuant to Executive Order 11821 and OMB Circular A–107, this proposal has been reviewed and a determination has been made that it is minor.

/s/ V. E. McKelvey
Director

Submittal of Information Concerning Development Plans to Coastal States

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.34, and applies to those States without a coastal zone management program approved by the Secretary of Commerce in accordance with the Coastal Zone Management Act of 1972 and amended in 1976. Section 250.34, as revised November 4, 1975 (40 FR 51199), provides in part as follows:

Development Plan. Prior to commencement of a development program on a lease, a plan of development shall be submitted to the Supervisor for approval. On leases issued after November 4, 1975, the Supervisor shall furnish a copy of the plan to the Governors of directly affected States except for that information identified by the Freedom of Information Act (P.L. 90–23) as being excluded from disclosure. The Governors shall have 60 days from receipt of this information in which to review and comment on the proposed plan.

Information for States. For any lease issued after November 4, 1975, the lessee shall deliver to the Governor of each directly affected State information concerning the onshore and offshore impact of the proposed plan of development. Such delivery shall be made 30 days before submission of the relevant development plan. The lessee shall notify the Governor and the Supervisor when final delivery of this information has been made.

The operator shall comply with the following requirements. Any departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. *Directly Affected States.* For the purpose of this Order, the States considered affected by operations in the Area are listed in Appendix A.

2. *Information to be Submitted to the States.* At least 30 days prior to submitting a plan of development for lease or unit operations to the Supervisor for approval, the lessee or operator shall furnish the Governor, or his designated representative, of each directly affected State and the Supervisor its assessment of the following information:

A. *Location*. The location, as to county, parish or general purpose local government, the size of any offshore and land-based facilities to be constructed, leased, or otherwise acquired or expanded, or offshore and land-based operations to be conducted or contracted for as a result of the proposed lease activity shall be identified and include:

(1) The amount of acreage required within the State for facilities and storage, right of way, and easements.

(2) The means to be used to transport oil and gas to shore, the routes such transportation will follow, and where possible, the estimated quantity of the oil and gas moving along such routes.

(3) An estimate of the frequency of boat and aircraft departures and arrivals, on a monthly basis, the onshore location of terminals, and the normal routes to be followed by each mode of transportation.

B. *Resource Requirements*. The requirements for land, labor, materials, and energy for the items identified in paragraph A above shall be stated and include:

(1) The approximate number of persons who will be engaged in onshore support activities and transportation, the approximate number of local personnel who will be employed for or in support of the development programs, indicating the major skills or crafts required from local sources and the estimated number of each such skill needed, and the approximate total number of persons who will be employed for the development programs.

(2) The approximate addition to the population of the local jurisdiction because of the development programs and the approximate number of persons needing housing and other facilities.

(3) An estimate of any significant quantity of natural resources including water, aggregate, or other major supplies and equipment to be procured within the States.

(4) The types of contractors or vendors which will be needed, although not specifically identified, which will place a demand on local goods and services such as transportation, food services, security, etc.

C. *Timeframes*. The timing of the development operations shall be estimated including:

(1) Sequence of events.

(2) Best estimate of time involved to complete the operations.

(3) When the actions are most likely to occur onshore and offshore.

D. *Personnel Involved*. List the names and addresses of the companies or contractors, known or anticipated, who will be conducting the various activities.

E. *Alteration of Plans*. Events that may with a reasonably good probability occur to significantly alter the proposed operations with respect to onshore impacts, including changes in oil and gas transportation operations, shall be described as well as how such operations shall be altered.

F. *Responsibility*. The lessee shall name a responsible individual knowledgeable in the provisions of the development plan with whom inquiries may be made by States representatives for purposes of clarification or explanation of the information provided. However, any request for additional information must be made to the Supervisor.

3. *Adequacy of Information*. If the Governor of an affected State, or his designated representative, advises the Supervisor within 30 days of receipt of the information provided by the lessee or operator that in the judgment of the State the requirements of paragraph 2 above have not been fulfilled, the Supervisor shall forward the information furnished by the lessee or operator, the comments from the State representative, and the stated position of the lessee or operator through the Regional Conservation Manager and the Chief, Conservation Division, to the Director for his determination as to the adequacy of the information.

The State representative and the lessee or operator shall be advised by the Supervisor of the Director's findings. If additional information is required to be submitted by the lessee or operator, the 60-day period of time for review by the States of a subsequently submitted plan of development shall not be considered to have commenced until such information has been received by the State.

4. *Development Plan*. The lessee or operator shall submit development plans for lease or unit areas at least six months in advance of the contemplated date for commencement of operations in order to allow time for an adequate review by personnel from the States and the Supervisor.

A. *Certification of Information*. The lessee or operator shall certify on each plan of development for a lease or unit area submitted for approval that the directly affected States have received the information set forth in paragraph 2 above at least 30 days prior to submission of the plan of development to the Supervisor. If any State does not desire the information, this fact should be stated and appropriate evidence from the State should be furnished.

B. *Proprietary Information*. The lessee or operator shall identify the information in the plan of development which, in his opinion, is excluded from required public disclosure by Subsection 552(b)(4) and (9) of the

Public Information Act, e.g., (1) trade secrets and commercial or financial information and (2) geological and geophysical information, data, and maps concerning wells.

C. *State Review of Development Plans.* The plan of development, excluding that information identified in paragraph 4.B. which is approved for exclusion by the Supervisor shall be provided by the Supervisor to the Governor, or designated representative, of each directly affected State. No approval action on the plan will be taken by Supervisor until comments are received from the appropriate State personnel or 60 days have elapsed from the date on which the State received the plan.

D. *Amendments to Plans of Development.* The operator shall submit amendments to a plan of development, including amendments which are determined to be minor, to the Supervisor and to the Governor or designated representative of each directly affected State. If the amendment is considered significant by the Supervisor, the review period may be extended for a period not to exceed 60 days from the States' receipt of the amendment.

An amendment may be considered significant if it results in an alteration of facilities or operations onshore and offshore that would change the impact.

5. *Modifications of Approved Plans of Development.* The lessee or operator shall submit to the Supervisor for approval a request for modification of an approved plan of development. If such modification, in the opinion of the Supervisor, would result in significant alteration of facilities or operations onshore and offshore, the procedures specified in the preceding paragraphs shall be followed.

6. *Extension of Leases.* Upon request of a lessee, the Supervisor may approve a suspension of operations for a nonproducing lease equal to the period of time in excess of 60 days which may be required for the previously described review, if such delay is not caused by the lessee and is in the interest of conservation.

/s/ Supervisor

Approved:

Chief, Conservation Division

Appendix A

Mid-Atlantic (Sales 40 and 49)—New York, New Jersey, Pennsylvania, Delaware, Maryland, Virginia, and North Carolina.

North Atlantic (Sales 42 and 52)—New York, Connecticut, Rhode Island, Massachusetts, New Hampshire, and Maine.

South Atlantic (Sales 43 and 54)—North Carolina, South Carolina, Georgia, and Florida.

Pacific (Sales 35, 48, and 53)—California.

Pacific (Sale 53)—Oregon and Washington.

Gulf of Mexico (East) (Sales 41, 45, 47, and 51)—Mississippi, Alabama and Florida.

Gulf of Mexico (Central) (Sales 41, 44, 45, 47, and 51)—Louisiana.

Gulf of Mexico (West) (Sales 41, 44, 47 and 51)—Texas.

Gulf of Alaska, Cook Inlet, Kodiak, Beaufort Sea, (Sales 39, CI, 46, and 50)—Alaska.

GEOLOGICAL SURVEY
OUTER CONTINENTAL SHELF (OCS)

Proposed National Orders Governing Oil and Gas Lease Operations

Notice is hereby given that, pursuant to revisions of 30 CFR 250.2(j), 250.3, 250.11, and 250.12, National Orders for the Outer Continental Shelf governing oil and gas lease operations are proposed as set forth below. The proposed revisions of these regulations are published concurrently in the Proposed Rules Section of the FEDERAL REGISTER.

As a result of the efforts of the Conservation Division task force for reviewing the OCS Operations Safety Program, it was determined that the existing Orders for individual areas of the OCS should be standardized. The task force concluded that the majority of the requirements of the existing OCS Orders are common to all areas of the OCS and that only a minority of the requirements arise from environmental, geological, geophysical, or geographical differences between the various areas.

The standardization of OCS Orders will be accomplished by the issuance of National OCS Orders which contain the requirements that are common to all areas of the OCS and Appendices which contain specific local requirements for each area. The National OCS Orders Nos. 1, 3, and 4, as proposed below, do not constitute additional requirements over the existing OCS Orders other than revisions to the existing requirements to incorporate new technological advances and improvements or changes in the regulations.

The proposed National OCS Order Nos. 2, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, and 15 are currently being developed and will be published at a later date. The existing OCS Orders will remain in effect until such time as all of the proposed National Orders are published in final form in the FEDERAL REGISTER.

Interested persons may submit written comments and suggestions on the proposed National OCS Orders to the Acting Chief, Conservation Division, U.S. Geological Survey, MS600, National Center, 12201 Sunrise Valley Drive, Reston, Virginia 22092, on or before July 29, 1977.

Note.—The Geological Survey has determined that this document does not contain a major proposal requiring preparation of an Inflation Impact Statement under Executive Order 11821 and OMB Circular A-107.

/s/ V. E. McKelvey,
Director.

UNITED STATES DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY—CONSERVATION DIVISION

National Order

OCS ORDER NO. 1

Effective

Identification of Wells, Platforms, Structures, and Subsea Objects

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.37.

The operator shall comply with the following requirements. All departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. *Identification of Fixed Platforms or Structures.* Platforms and structures shall be identified at two diagonal corners by a sign with letters and figures not less than 30 centimeters (12 inches) in height with the following information: The name of lease operator, the area name shown on OCS Official Protraction Diagrams (or, where no name has been assigned, the Protraction Diagram number), the block number in which the platform or structure is located, and the platform or structure designation. The information shall be abbreviated as in the following example:

The Blank Oil Company operates "C" platform on Block 999 of the Salisbury Area.

The identifying sign on the platform would indicate: BOC-SAL-999-C.

2. *Identification of Nonfixed Platforms or Structures.* Floating semi-submersible platforms, bottom-setting mobile rigs, and drilling ships shall be identified by one sign with letters and figures not less than 30 centimeters (12 inches) in height affixed to the derrick so as to be visible from off the vessel and containing the following information: The name of the lease operator, the area designation based on OCS Official Leasing Maps, the block number, the OCS lease number, and the well number.

3. *Identification of Wells.* The OCS lease and well number shall be painted on, or a sign affixed to, each singly completed well. In multiple completed wells, each completion shall be individually identified at the well head. All identifying signs shall be maintained in a legible condition.

4. *Identification of Subsea Objects.* All subsea objects resulting from lease operations, and presenting a hazard to navigation or to deployment of commercial fishing devices, shall be identified with navigational markings. Such identification shall be in accordance with an approved Coast Guard design. These navigational markings shall be maintained on-site and operable at all times as long as the obstruction remains.

Approved:

Acting Chief, Conservation Division.

UNITED STATES DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY—CONSERVATION DIVISION

National Order

OCS ORDER NO. 3

Effective

Plugging and Abandonment of Wells

This Order is established pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.15. The operator shall comply with the following minimum plugging and abandonment procedures which have general application to all wells drilled for oil and gas. Plugging and abandonment operations must not be commenced prior to obtaining approval from an authorized representative of the Geological Survey. Oral approvals shall be in accordance with 30 CFR 250.13. All departures from the requirements specified in this Order must be approved pursuant to 30 CFR 250.12(b).

1. *Permanent Abandonment.*

1.1 *Isolation in Uncased Hole.* In uncased portions of wells, cement plugs shall be spaced to extend 30 meters (100 feet) below the bottom to 30 meters (100 feet) above the top of any oil, gas, and fresh water zones so as to isolate them in the strata in which they are found and to prevent them from escaping into other strata. Additional cement plugs may be required to protect other minerals or to prevent migration of fluids in the well bore.

1.2 *Isolation of Open Hole.* Where there is open hole below the casing, a cement plug shall be placed in the deepest casing string by methods (a) or (b) below or, in the event lost circulation conditions exist or are anticipated, the plug may be placed in accordance with (c) below:

(a) A cement plug placed by displacement method so as to extend a minimum of 30 meters (100 feet) above and 30 meters (100 feet) below the casing shoe.

(b) A cement retainer with effective back pressure control set not less than 15 meters (50 feet), nor more than 30 meters (100 feet), above the casing shoe with a cement plug calculated to extend at least 30 meters (100 feet) below the casing shoe and 15 meters (50 feet) above the retainer.

(c) A permanent type bridge plug set within 45 meters (148 feet) above the casing shoe with 15 meters (50 feet) of cement on top of the bridge plug. This plug shall be tested prior to placing subsequent plugs.

1.3 *Plugging or Isolating Perforated Intervals.* A cement plug shall be placed opposite all open perforations (perforations not squeezed with cement) extending a minimum of 30 meters (100 feet) above and 30 meters (100 feet) below the perforated interval or down to a casing plug, whichever is less. In lieu of the cement plug, the following two methods are acceptable, provided the perforations are isolated from the hole below:

(a) A cement retainer with effective back pressure control set not less than 15 meters (50 feet) nor more than 30 meters (100 feet) above the top of the perforated interval with a cement plug calculated to extend at least 30 meters (100 feet) below the bottom of the perforated interval and 15 meters (50 feet) above the retainer.

(b) A permanent type bridge plug set within 45 meters (148 feet) above the top of the perforated interval with 15 meters (50 feet) of cement on top of the bridge plug.

1.4 *Plugging of Casing Stubs.* If casing is cut and recovered thereby leaving a stub inside the next larger string, a cement plug will be set so as to extend 30 meters (100 feet) above and 30 meters (100 feet) below the stub, or a retainer set 15 meters (50 feet) above the stub with 45 meters (150 feet) of cement set below and 15 meters (50 feet) above. A permanent bridge plug set 15 meters (50 feet) above the stub and capped with

15 meters (50 feet) of cement shall be used if the foregoing methods cannot be used. However, if the stub is below the next larger string, plugging must be accomplished in accordance with subparagraphs 1.1 and 1.2 above.

1.5 *Plugging of Annular Space*. No annular space that extends to the ocean floor shall be left open to drilled hole below. If this condition exists, the annulus shall be plugged with cement.

1.6 *Surface Plug Requirement*. A cement plug of at least 45 meters (148 feet), with the top of the plug 45 meters (148 feet) or less below the ocean floor, shall be placed in the smallest string of casing which extends to the surface.

1.7 *Testing of Plugs*. The setting and location of the first plug below the top 45-meter (148-foot) plug will be verified by either (1) placing a minimum pipe weight of 6,800 kilograms (15,000 pounds) on the plug or, where this plug is placed utilizing a cement retainer or bridge plug, it is only necessary that the setting of the retainer or bridge plug be verified by placing at least 6,800 kilograms (15,000 pounds) on it prior to placing cement on top, or (2) testing with a minimum pump pressure of 6,900 kPa (1,000 psi) with no more than a 10-percent pressure drop during a 15-minute period.

1.8 *Mud*. Each of the respective intervals of the hole between the various plugs shall be filled with mud fluid of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling such interval.

1.9 *Clearance of location*. All casing and piling shall be severed and removed to a depth of at least 5 meters (16 feet) below the ocean floor or at a depth as approved by the District Supervisor after a review of data on the ocean bottom conditions. The operator shall verify that the location has been cleared of all obstructions.

2. *Temporary abandonment*. Any drilling well which is to be temporarily abandoned shall be mudded and cemented as required for permanent abandonment except for requirements 6 and 9 of section 1 above. When casing extends above the ocean floor, a mechanical bridge plug (retrievable or permanent) shall be set in the casing between 5 and 60 meters (16 and 197 feet) below the ocean floor.

Approved:

UNITED STATES DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY—CONSERVATION DIVISION

National Order

OCS ORDER NO. 4

Effective

Suspension and Determination of Well Producibility

The preamble to this Order is common to all areas of the Outer Continental Shelf. Refer to National OCS Order No. 4.

1. *Oil Wells*. Refer to National OCS Order.
2. *Gas Wells*. Refer to National OCS Order.
3. *Production Capability*. The following may be considered as acceptable evidence that a well is capable of producing in paying quantities:

A. A resistivity log of the well showing a minimum of 15 feet of producible sand in one section which does not include any interval which appears to be water saturated. All of the section counted as producible shall exhibit the following properties:

(1) Electrical spontaneous potential exceeding 20 negative millivolts beyond the shale base line. If mud conditions prevent a 20 negative millivolt reading beyond the shale base line, a gamma ray log deflection of at least 70 percent of the maximum gamma ray deflection in the nearest clean water-bearing sand may be substituted.

(2) A minimum true resistivity ratio of the producible section to the nearest clean-water sand of at least 5:1.

(3) A porosity log indicating porosity in the producible section.

B. Side wall cores and core analysis which indicates that the section is producible.

C. The aforementioned criteria will absolutely ascertain that a well is producible. However, recognizing the fact that rocks in the Gulf of Mexico Area do not possess the same physical properties and therefore do not lend themselves to one single method of log analysis, the Geological Survey may, at its discretion, accept sound log interpretation techniques which conclusively demonstrate that a well would produce water-free hydrocarbons in its particular area, even though it might not qualify under A and B. The operator can support its interpretation by submitting further evidence such as wireline formation tests and/or mud logging analysis.

4. *Witnessing and Results*. Refer to National OCS Order.

/s/ D. W. SOLANAS,
Area Oil and Gas Supervisor.

Approved:

Acting Chief, Conservation Division.

Appendix H

Title 30 Code of Federal Regulations Part 250.34 Drilling and Devlopment Program

FROM FEDERAL REGISTER VOL. 40, NO. 213—TUESDAY, NOVEMBER 4, 1975

CHAPTER II - GEOLOGICAL SURVEY, DEPARTMENT OF THE INTERIOR

Part 250—Oil and Gas Sulphur Operations in the Outer Continental Shelf

DRILLING AND DEVELOPMENT PROGRAMS

On pages 42559 and 42560 of the September 15, 1975, edition of the Federal Register (40 FR 42559-42560) there was published a proposal to modify regulation 30 CFR 250.34, Drilling and Development Programs. Page 43036 of the September 18, 1975, edition (40 FR 43036) contained a correction. The intent of the proposed modification is to set forth procedures for State consideration of developments proposed by lessees of Federal Outer Continental Shelf Lands. The proposed modification will provide affected States with information and an opportunity to review and comment concerning developments of oil and gas by such lessees. Lessees will be required to deliver information on planned developments to affected States before submitting development plans to the U.S. Geological Survey.

The regulation recognizes that development plans often contain information which the lessee considers to be confidential. Two specific classes of information often contained in development plans are exempted from disclosure under the Freedom of Information Act. These will not be disclosed under the proposed modification.

The Outer Continental Shelf Lands Act (43 U.S.C. 1331-1343) provides in section 5(b) (2) that leases may be cancelled for failure to comply with "regulations issued under this Act and in force and effect on the date of issuance of the lease". In keeping with this provision, the revised regulation 30 CFR 250.34 herein promulgated will be applicable only to leases issued after the date of this rulemaking.

Interested persons were given until October 15, 1975, to submit comments regarding the proposed modification of 30 CFR 250.34. The notice of the proposed modification indicated that significant comments would be published at the time of the final rulemaking. Because of the volume of the comments received, they are not published herein but are available on request from the Director of the U.S. Geological Survey, National Center, Reston, Virginia 22092. The comments received represented a wide range of views on the necessity, value, legality and consequences of the proposed modification.

After considering the comments received the following revisions were made in the proposed modifications:

1. Added provisions to paragraphs (b) and (c) allowing States to waive review of development plans and receipt of information.
2. Added provisions to paragraphs (b) and (c) requiring that Governors' comments on development plans and information be sent to both the Supervisor and the lessee.
3. Added a procedure to paragraph (b) for treatment of amendments to development plans made before their approval.
4. Clarified requirements for information under paragraph (c). (Further clarification will be forthcoming in relevant OCS Orders).
5. Added a provision to paragraph (c) which allows previously published information to be incorporated by reference rather than duplicated in the information for States.
6. Added a provision to paragraph (c) providing for extension of the term of the lease in cases where review requires delays in excess of the 60-day period.
7. Added to paragraph (e) the condition that the Supervisor determine that proposed modifications of approved development plans significantly affect the interest of a State before requiring that the procedures under paragraphs (b) and (c) be applied.

The proposed modification to 30 CFR 250.34 is adopted as set forth below and is effective immediately. OCS Orders will be issued subsequently to define more specifically the content and timing of information to be provided by lessees to the States.

/s/ THOMAS S. KLEPPE,
Secretary of the Interior

OCTOBER 31, 1975

Section 250.34 is revised to read as follows:

NO. 250.34 DRILLING AND DEVELOPMENT PROGRAMS.

(a) Exploratory drilling plan. Prior to commencing each exploratory drilling program on a lease, including the construction of platforms, the lessee shall submit a plan to the Supervisor for approval. Each plan for the leased area shall include (1) a description of drilling vessels, platforms, or other structures showing the location, the design, and the major features thereof, including features pertaining to pollution prevention and control; (2) the general location of each well including surface and projected bottom hole location for directionally drilled wells; (3) structural interpretations based on available geological and geophysical data; and (4) such other pertinent data as the Supervisor may prescribe.

(b) Development plan. Prior to commencing each development program on a lease, the lessee

shall submit a plan to the Supervisor for approval. The plan shall include all information specified in paragraph (a) of this section in detail. The development plan except for those portions which the lessee shall designate, with the Supervisor's approval as (1) trade secrets and commercial or financial information which are privileged or confidential or (2) geological and geophysical information, data and maps concerning wells, shall be provided by the Supervisor to the Governors of directly affected States, as designated by the Supervisor. Any State not wishing to review a development plan may so indicate to the Supervisor. Prior to the Supervisor's approval of the plan, a period of 60 days, commencing with the date of the Governor's receipt of the development plan, shall be provided to each Governor for review of the plan and the submission of comments, to both the Supervisor and the lessee. If the Governors' comments are received before the 60 day period ends, the Supervisor may then proceed to act upon the plan without further delay. After the 60 day period ends, the Supervisor may act upon the plan even if comments have not been received from the Governor. Amendments to development plans may be submitted during the period before this approval. Such amendments shall be sent by the Supervisor to the Governors who have received copies of the development plans. In such cases, the Supervisor shall determine if the amendment is significant and warrants an extension of the 60 day review period.

(c) Information for States. Prior to submission of a development plan, the lessee shall deliver to the Governor of each directly affected State, as designated by the Supervisor, information about the development to be proposed. Any State not wishing to have such information may so indicate to the Supervisor. The final delivery of such information shall be made at least 30 days before submission of the relevant development plan, at which time the lessee shall notify both the Governor of each directly affected State and the Supervisor that such final delivery has been made. When submitting a development plan, the lessee shall certify to the Supervisor that he has, at least 30 days before such submission, provided the required information about the development proposed in that plan to the Governor of each directly affected State. The information provided to the States under this paragraph (c) which is not to be a part of the development plan itself, shall include a description of all offshore and onshore facilities and operations proposed by the lessee or directly related to the proposed development including location, size, requirements for land, labor, materials and energy, and timing of development and operation, and other related information as may be required by the Supervisor. Information available in previously published documents, such as Environmental Impact Statements, may be incorporated by reference. Copies of all information given to Governors under this paragraph shall be provided to the Supervisor. A State provided such information shall indicate to the Supervisor and to the lessee at the earliest practicable time whether the State concurs that the information meets the requirements of this paragraph and any subsequent implementing Orders issued by the Supervisor. If a State fails to provide such notification within 30 days after the final delivery of the information, the State's concurrence will be conclusively presumed. If a State notifies the Supervisor that the information does not in its judgment satisfy the requirements, then the Director shall review the information, the specific comments of the Governor, and the position of the lessee and shall make a determination either that the information satisfies the requirements or that the lessee must provide additional information. The Director shall make his review and determination as expeditiously as possible after receipt of such notification. In the event the Director determines that the information satisfies the requirements, then the 60 day period for comments shall begin on the date of his determination. In the event the Director determines that the requirement has not been satisfied, the 60 day comment period will not begin until the State shall have received the additional information required. If, with respect to any non-producing lease, the procedures specified under paragraphs (B) and (C) require delay in excess of the 60 days for review specified in those paragraphs, and the delay is in the interest of conservation and is not caused by the lessee, there shall, if the lessee so requests, be a suspension of operations for a period equal to the delay in excess of 60 days and the lease shall be extended for a period of time equal to the period of suspension.

(d) Drilling applications. Prior to commencing drilling operations either under an exploratory or development plan, the lessee shall submit an Ap-

plication for Permit to Drill (Form 9-331C) to the Supervisor for approval. The application shall include the integrated blowout prevention, mud, casing and cementing program for the well, and shall meet the requirements specified in No. 250.41(a), and contain the information specified in No. 250.91(a), and shall conform with the approved exploratory or development plan.

(e) Modifications. The lessee shall submit: (1) All requests for modifications of an approved exploratory or development plan in writing to the Supervisor for approval and (2) all notices of changes to plans set forth in approved Application for Permit to Drill on Sundry Notices and Reports on Wells (Form 9-331), except that these requirements shall not relieve the lessee from taking appropriate action to prevent or abate damage, waste, or pollution of any natural resource or injury to life or property. When the Supervisor shall determine that the proposed modification of an approved development plan is major and would directly and significantly affect the interest of a State, he shall require the lessee to follow the same procedures with respect to the State as those provided in No. 250.34(b) and (c).

Appendix I

Influences of Petroleum Hydrocarbons and Heavy Metals on Marine Food Webs

APPENDIX I

THE INFLUENCES OF PETROLEUM HYDROCARBONS AND HEAVY METALS ON MARINE FOOD WEBS

1. Biogenic and Petroleum Hydrocarbons
2. Uptake of Petroleum Hydrocarbons and Heavy Metals
3. Storage and Metabolism
4. Discharge or Depuration
5. Food Web Magnification
6. Microbial Decomposition
7. Carcinogenicity
8. Heavy Metals
9. Bibliography

1. Biogenic and Petroleum Hydrocarbons

Marine organisms contain and synthesize hydrocarbons under natural conditions. Some of the biogenic hydrocarbons which are important to the survival of the organism can be the same as or similar to the petroleum hydrocarbons (PHC) found in crude or refined oil. This fact has several implications. The detection of the origin of hydrocarbons can be difficult for the analytical chemist. Misidentification by consuming organisms or interference with chemical cues can have pronounced ecological effects. Because many petroleum hydrocarbons are natural components of the biosystem, they may be incorporated in the system without the interference or harm caused by others such as chlorinated hydrocarbons. Other petroleum hydrocarbons, however, may cause harm or interference with certain biological processes.

Examination of crude oils and most refined products indicates that they are extremely complex mixtures of organic compounds of which hydrocarbons comprise the most numerous and abundant fractions.

In their extensive literature review, Anderson, Clark and Stegeman (1974) indicated some basic differences between biogenic and petroleum hydrocarbons. Crude oil and oil products are varied mixtures that contain molecules of different size in fairly even distribution ratios. Conversely, organisms possess specific biosynthetic pathways which favor the production of hydrocarbons in preferred and consequently narrower size ranges. Petroleum hydrocarbons are rich in toxic aromatic hydrocarbons and cycloparaffins. They also contain isoprenoid hydrocarbons (alkanes with methyl branches) ranging from about C_{11} to C_{22} and beyond, while organisms are limited to isoprenoids in the range C_{18} to C_{20}. Crude oil is devoid of the olefins or alkenes which are abundant in most organisms.

Anderson et al. (1974) summarized the occurrence of the various classes of hydrocarbons from petroleum and biological origins.

a. Saturated hydrocarbons (alkanes or paraffin)

Both short and long-chain alkanes occur naturally in marine organisms. They are not as toxic to organisms at low concentrations as the aromatics are, but they may cause anaesthesia and narcosis or interfere directly with reception of the chemical cues. They can interfere with feeding, nutrition and communication in aquatic organisms (Goldacre, 1968; Whittle and Blumer, 1970; Blumer et al., 1972). Branched alkanes including pristane, an isoprenoid, have been found in marine macroorganisms. In some plankton and fish, pristane is the most abundant alkane present. In organisms, the biogenic alkanes of C_{60} and smaller are predominantly odd-numbered chains, while in petroleum odd and even numbered chains occur in a 1:1 ratio.

Petroleum contains abundant amounts of saturated hydrocarbons. Crude oil and most refined oil contain a series of n-alkanes with chain lengths of C_1 to C_{60}. Branched alkanes, including the isoprenoids pristane, farnsane and phytane, are also present. Long chain saturated hydrocarbons occur in petroleum and refined products except for lubricating oil.

b. Unsaturated hydrocarbons (olefins or alkanes)

Alkenes often account for a major percentage of the hydrocarbons found in aquatic organisms, and include squalene in basking shark liver oil and cod liver oil, and the polyolefins, hexeicosahexane and carotene, prevalent in algae. According to Blumer (1969) alkenes may serve in biochemical communications, but their exact biological roles are poorly understood.

Olefinic hydrocarbons are rarely present in crude oils, but are formed in some refining processes and are present in gasoline and cracked petroleum products.

c. Alicyclic hydrocarbons

Hydrocarbons containing one to three non-aromatic rings are present in several herbs and other land plants. Most are classified as terpenes because of their biosynthetic origin from isoprene.

d. Aromatic hydrocarbons

Although Gerarde and Gerarde (1961) reported several instances of low-boiling aromatic hydrocarbons in land plants, the occurrence of aromatics in marine organisms is debatable. Blumer et al. (1969) did not isolate aromatic hydrocarbons from plankton, and DiSalvo et al. (1975) were unable to detect aromatics in mussels (*Mytilus californianus*) taken from unpolluted environments. As suggested by Borneff et al. (1968), higher boiling aromatics may be synthesized by marine organisms. Many species, including bacteria, metabolize polynuclear aromatics and excrete the oxidation products.

Aromatics, particularly naphthalenes, have repeatedly been reported as the most toxic of the hydrocarbons. Their interference with feeding activities and other biological processes is important and should be given prime consideration.

Aromatic hydrocarbons represent a large percentage of the components of crude oil and an even larger percentage of the components of a refined product.

e. Nonhydrocarbon compounds in petroleum

Although more than 75% of most petroleum is composed of hydrocarbons, many other compounds (some toxic) are present in varying concentrations. These include cresols, xylenols, naphthols, quinolines, pyridines and hydroxybenzoquinolines which are of particular concern because of their great toxicity and solubility in water.

Apparently, except for the UV-fluorescent examinations by Zitko and Carson (1970), no analyses of nonhydrocarbon components for use in estimating petroleum contamination of aquatic organisms have been reported. Unfortunately, no degradation studies using these compounds are in the commonly-accessible literature (Anderson et al. 1974).

2. Uptake of Petroleum Hydrocarbons

Hydrocarbons are available to marine organisms in several different physical and chemical forms and uptake is greatly influenced by these factors. Hydrocarbons are essentially hydrophobic compounds and consequently have very low solubilities in water, generally in the part per million (ppm) to part per billion (ppb) range (National Academy of Sciences, 1975). Because of this hydrophobic characteristic, most of the oil in a slick will remain on the ocean surface or adsorb to particulate matter and become incorporated into the bottom sediments instead of dissolving in the water column. The relative percentages of hydrocarbons involved in each of these processes depend upon environmental variables such as temperature, wind speed, wave action, etc. Various types of hydrocarbons in the petroleum mixture, in other words, low molecular weight paraffins (alkanes) and aromatics, have relatively high solubilities in water, however, these compounds are relatively volatile and are for the most part, lost to the atmosphere by evaporation. Petroleum, therefore, is presented to pelagic organisms in dissolved, dispersed, or suspended (floating tar lumps) forms and to benthic organisms in dissolved, dispersed, suspended or sedimented forms.

Petroleum hydrocarbons (PHC) may enter the food web by several means. Petroleum adsorbed to living or dead particles may be ingested. Uptake of PHC by the ingestion of prey species which have accumulated PHC within the body tissues can also occur. Another method is the uptake of dissolved or dispersed petroleum via the gills or body surface.

The importance of several of these uptake methods is still largely unknown, but will vary with the species involved, the method of feeding and respiration of the organisms involved, the habitat, the state of the sea, and the petroleum itself. Evidence indicates that the majority of hydrocarbons enter molluscs, crustaceans and fish via gill membranes (Anderson, Clark, and Stegeman, 1974). It would seem logical then that this would also be an important method of uptake in other marine groups, although the relative importance of transport through the body surface of marine worms with exposed soft bodies is unknown. Although ingestion of contaminated food and sediment particles may be important in marine mammals and some fish, its relative relationship to the transport across body surface membranes is still unknown.

According to the National Academy of Sciences report (1975):

> Equlibration of hydrocarbons can occur between organisms and the seawater that passes over their gills or other membranes exposed to seawater. This may be the most important route for most aquatic animals since they process such large amounts of water during food collection and respiration. One can calculate from the hydrocarbons measured in coastal waters (Stegeman and Teal, 1973; Brown et al. 1973) of 10 μg/liter and a level in food of 10 mg/g that an animal would be exposed to more than an order of magnitude larger amount of hydrocarbons in the water processed to obtain oxygen for metabolism of the food than that amount present in the food itself. Stegeman and Teal believe that uptake from the water is the major route by which oysters accumulated hydrocarbons from the water. In other situations, uptake from sediments could also be important.

Dissolved hydrocarbons were taken up by the gill tissue of the mussel *Mytilus edilus*, and then transferred to other tissues (Lee et al. 1972a). Electron microscopic studies on the uptake of iron suggest that the gill tissue of this mussel has a micellar layer on the surfaces of the gill that is responsible for the adsorption of hydrophobic compounds (Pasteels, 1968). Work on the uptake of dissolved hydrocarbons by marine fish also demonstrated the entrance of hydrocarbon through the gills (Lee et al. 1972b).

Yevich and Barry (1970) reported on tissue damage brought about by exposure to crude oils and other pollutants; such damage includes sloughing of the epithelium and atypical basal cell hyperplasia of the ciliated inner gills of quahogs (*Mercenaria mercenaria*). The question also arises, then, as to the effect the loss of the protective membrane coatings of the gills has on the rate of absorption of hydrocarbons from water.

Invertebrates such as molluscs and barnacles, which have the ability to isolate themselves from the environment through shell closure may employ a behavior mechanism which protects them for limited amounts of time from excessive uptake of PHC. Stegeman and Teal (1973) exposed oysters, *Crassostrea virginica*, to varying concentrations of No. 2 fuel oil for two days. The data suggested that, for concentrations up to 450 ug/l (ppb), there was a direct relationship between the hydrocarbon concentration in the water and uptake rate, while at higher concentrations the rate of uptake fell (Figure I-1). The reason for this was that the oysters remained tightly closed when exposed to concentrations of 900 mg/l. Even though oysters can tolerate many forms of environmental irritants so common in estuaries by shell closure and similar behavior mechanisms (Menzel, 1955), other marine molluscs may not exhibit the same degree of adaptability.

Even though PHC are taken into the gut through ingestion, they may not necessarily become incorporated into body tissues, but may instead be passed directly through the organism as feces. Following the *Arrow* incident in Chedabucto Bay, plankton were observed to ingest large quantities of Bunker C oil and eliminate them in the form of fecal matter (up to 7% Bunker C oil by weight) (Conover, 1971). The plankton always voided the small ''oil'' particles within 24 hrs. and showed no signs of stress when viewed under a dissecting microscope. No chemical analysis of the fecal matter or of the whole copepods was reported, however, which might have provided some indication of whether and what degree of degradation or partitioning of the oil took place.

Parker (1970) also demonstrated the presence of considerable quantities of oil in the guts and fecal pellets of copepods and barnacle larvae. The fact that the oil passes unchanged into the fecal material is of considerable interest since oil from a slick can be grazed by the plankton and the ingested oil concentrated in the feces. Parker (1971) calculated that copepods (*Calanus finmarchicus*) could encapsulate up to 1.5 X 10^4 g of oil per day per individual. For example, a population of 2,000 individuals/m^3 covering an area of 1 km^2 to a depth of 10 m could remove as much as three tons of oil daily if the oil's concentration is 1.5 ppm or greater. Fecal pellets can then be eaten by other members in the food web.

Alyakrinskaya (1966) found that the mussel *Mytilus galloprovincialis* in the Black Sea could tolerate high concentrations of oil (up to 20 ml/liter of an undefined type of oil). During filtration of oil-polluted water, the molluscs formed pseudofeces from oil connected by mucous—to a degree comparable with transferring the oil to large, denser particles as Conover and Parker have suggested for copepods.

According to Anderson et al. (1974), a significant amount of PHC is taken up and accumulated, at least temporarily, within the body tissues of most fishes and invertebrates during spills. Data shown in Table I-1 (presumably contaminated tissues) and Table I-2 (natural tissue hydrocarbon levels) should be treated with a certain amount of caution, however, because of the number of variables involved. The methods of analyses, UV absorption spectrophotometry, infrared spectrometry, mass spectrometry and the various chromatography proceudres, measure hydrocarbons in a different manner and consequently produce slightly different results. The other significant variable is the composition of the oil itself.

According to Anderson et al. (1974)

Levels of PHC contamination in a wide variety of edible marine organisms are listed in Table I-1. The data shown in this table relate to organisms collected from localities presumed to be high in PHC contamination, and therefore the compounds detected are likely to be petroleum derived. These samples, presumed by

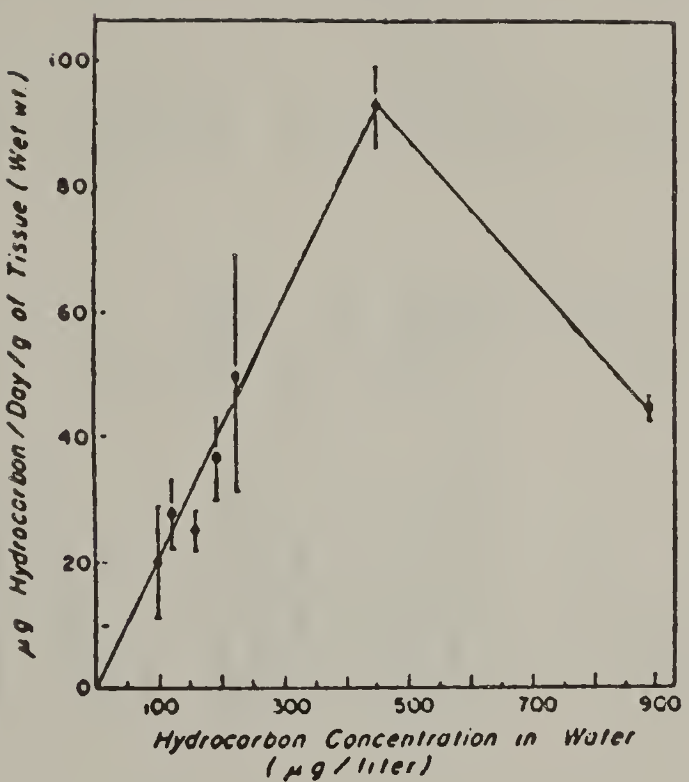


Fig 1—1 *Crassostrea virginica.* Initial rate of petroleum hydrocarbon uptake by oysters versus hydrocarbon concentration in the water. Oysters were assayed after 2 days exposure at indicated hydrocarbon concentration. Each point represents average of 2 determinations using high fat-content oysters

Table I-1 Tissue Samples - Presumably Contaminated (from Anderson et al., 1974)

SPECIES	PROBABLE SOURCE	HC TYPE 1/	ANALYSIS	WET ug/g	REFERENCE
Macro algae					
Fucus sp.	Spill - Bunker C	n-paraffins	GC	5.8	Clark *et al.*, 1973
Snails					
Littorina littorea	Spill	Bunker C aromatics	Fluoro	27-600	Scarratt & Zitko, 1972
Thais lamellosa	Spill -#2 fuel oil	n-paraffins	GC	5.4	Clark, 1974
Clams					
Mercenaria mercenaria	Sewage effluent	C_{16-32}	GC	16	Farrington & Quinn, 1973
Mya arenaria	Spill	#2 fuel oil	GC/MS	26	Blumer *et al.*, 1970b
Oysters					
Crassostrea vriginica	Chronic	paraffins, mono & di-aromatics	GC/MS TLC	236	Ehrhardt, 1972
	Harbor	C_{17-32}	GC	10	Stegeman, 1974
	Spill	#2 fuel oil	GC/MS	70	Blumer et al., 1970a
	Chronic	Polynuclear aromatics	UV	1	Cahnmann & Kuratsane, 1957
	Chronic-harbor	Saturates	GC/MS	15	Meiggs, 1973 (Galveston)
	" "	"	GC	13-29	" " (San Francisco)
	" "	Total HC	GC	160	R.D.Anderson, 1973 (Galveston Red Bluff Reef)
	" "	Saturates, C_{12-24}	GC	11.2	R.D.Anderson, 1973 (Galveston Halfway Reef)
		Dimethylnaphthalenes	GC	0.6	"
		Trimethylnaphthalenes	GC	0.6	"
Mussels					
Modiolus modiolus	Spill	#2 fuel oil	GC	218	Burns & Teal, 1971
	Spill	Bunker C aromatics	Fluoro	21-372	Scarratt & Zitko, 1972

1/ Though only n-paraffins were indicated in some cases, the probable presence of other petroleum-type hydrocarbons, e.g. aromatics, is not to be excluded.

Table I-1 (continued)

SPECIES	PROBABLE SOURCE	HC TYPE	ANALYSIS	WET ug/g	REFERENCE
Mytilus edulis	Spill	Bunker C aromatics	Fluoro	77-103	Zitko, 1971
	Chronic harbor	n-paraffins	GC	0.97	Clark & Finley, 1973b
	Spill-#2 fuel oil	"	GC	1.4	"
Mytilus californianus	Spill-Bunker C	"	GC	0.87	"
Scallops					
Acquipecten irradians muscle	Spill	#2 fuel oil	GC	7-14	Blumer *et al.*, 1970b
Barnacles					
Mitella polymerus	Spill-Bunker C	n-paraffins	GC	11.8	Clark *et al.*, 1973
Crabs					
Cancer irroratus	Spill	Bunker C aromatics	Fluoro	7-11	Scarratt & Zitko, 1972
Hemigrapsus nudus	Spill-Bunker	n-paraffins	GC	2.9	Clark *et al.*, 1973
Lobster					
Homarus americanus-gut	Spill	Bunker C aromatics	Fluoro	103-130	Scarratt & Zitko, 1972
stomach	"	"	"	15-230	"
claw-muscle	"	"	"	2-3	"
Abdominal muscle	"	"	"	1-4	"
Urchins					
Stronglyocentrotus droebachiensis	Spill-Bunker C	Bunker C aromatics	Fluoro	17-94	Scarratt & Zitko, 1972
Mullet					
Mugil cephalus-flesh	Chronic-harbor	Kerosene taint	GC/MS	~860	Shipton *et al.*, 1970
Whitefish-flesh	Spill	Diesel oil	GC	29-88	Ackman & Noble, 1973
Flatfish	Chronic-coast	C_{14-20}	GC	4	Bowen, 1971

TABLE I-2 Natural Tissue Hydrocarbon Levels (from Anderson et al., 1974)

SPECIES	LOCALITY	HC TYPE	ANALYSIS	WET ug/g	REFERENCE
Macro Algae					
Nereocystus (kelp)	Puget Sound, Wash.	n-paraffins	GC	0.74	Clark, 1974
Ulva sp. (sea lettuce)	"	"	"	20.3-23.0	"
Fucus sp.	Puget Sound, Wash.	n-paraffins	GC	3.03-55.7	"
	Washington Coast	"	"	9.51-57.2	"
	New Hampshire	"	"	8.96	Clark & Blumer, 1967
	Woods Hole, Mass.	"	"	34.9	"
	Falmouth, Mass.	"	"		"
Snails					
Thais lamellosa	Puget Sound, Wash.	n-paraffins	GC	0.06-1.5	Clark, 1974
Littorina littorea	Eastern Canada	Aromatics	Fluoro	11	Zitko, 1971
Littorina sp.	Valdez, Alaska	n-paraffins	GC	16.1	Clark, 1974
Limpets					
Notoacmea scutum	Puget Sound, Wash.	n-paraffins	GC	2.5	Clark, 1974
Chiton					
Mopalia sp.	Puget Sound, Wash.	n-paraffins	GC	0.50	Clark, 1974
Clams					
Mercenaria mercenaria	Narrangansett Bay, R.I.	Total HC	GC	2.9	Farrington & Quinn, 1973
Mya arenaria	Eastern Canada	Aromatics	Fluoro	8	Zitko, 1971
Mya sp.	Valdez, Alaska	C_{16-28}	GC	1.1	Kinney, 1973
Rangia cuneata	Trinity Bay in Galveston, Texas	Naphthalene	UV Spec	0.16	Cox & Anderson, 1974
		Methylnaphthalene	"	0.11	"
		Dimethylnaphthalene	"	0.06	"
Oysters					
Crassostrea virginica	Redfish Reef in Galveston Bay	Saturated HC	GC/MS	1.5	Meiggs, 1973
	Aransas Bay, Texas	Saturated HC	GC/MS	1	Meiggs, 1973
	Quisset, Mass.	Total HC	GC	1-2	Stegeman & Teal, 1973
	Galveston Island				
	East Lagoon	Total HC	GC	<2.0	R.D.Anderson, 1973
	Eight Mile Road Reef	"	"	<2.0	"

Table I-2 (continued)

SPECIES	LOCALITY	HC TYPE	ANALYSIS	WET ug/g	REFERENCE
	Eight Mile Road Reef	Saturated	GC	<0.1	R.D. Anderson, 1973
	"	Aromatics	"	<0.1	R.D. Anderson, 1973
Ostrea edulis	Newport, Oregon	n-paraffins	GC	0.35	Clark *et al.*, 1974
Mussels					
Mytilus edulis	Puget Sound, Wash.	n-paraffins	GC	0.37-21.6	Clark, 1974
	Valdez, Alaska	"	"	0.40-0.95	"
	Newport, Oregon	"	"	0.34	Clark *et al.*, 1974
	Eastern Canada	Aromatics	Fluoro	3	Zitko, 1971
	Valdez, Alaska	C_{16-28}	GC	1.9	Kinney, 1973
Mytilus californianus	Washington coast	n-paraffins	GC	0.45	Clark & Finley, 1973b
	Puget Sound, Wash.	"	"	0.088-0.58	Clark, 1974
Barnacles					
Mitella polymerus	Washington coast	n-paraffins	GC	1.41	Clark *et al.*, 1973
	Puget Sound, Wash.	"	"	1.22-4.54	Clark, 1974
Balanus cariosus	Washington coast	n-paraffins	GC	0.66	Clark, 1974
Scallop					
Acquipecten irradians	Waquoit Bay, Mass.	Saturates	GC	2.3-55	Blumer *et al.*, 1970a
Shrimp					
Pandalis borealis	North Atlantic	Saturates	GC	43.6	IDOE, 1972
Unidentified species	Artic Ocean	n-paraffins	GC	0.37-21.6	Clark, 1974
Palaemonetes pugio	Galveston Island Marsh at Eight Mile Road	Saturated Total (C_{20-31})	GC	24.8	Tatem & Anderson, 1974
		(C_{22-26},each)	"	3.1-3.9	"
		C_{23}	"	3.8	"

Table I-2 (continued)

SPECIES	LOCALITY	HC TYPE	ANALYSIS	WET ug/g	REFERENCE
Palaemonetes pugio	Marsh at Eight Mile Rd	Saturated Total			
		(C_{21-26})	GC	10.9	Tatem & Anderson, 1974
		C_{23}	"	3.9	"
Penaeus setiferus (postlarvae)	Mariculture by Dow Chemical	Saturated Total	GC	15.0	Cox & Anderson, 1974
		Aromatics Total	"	8.0	"
Crabs					
Hemigrapsus nudus	Washington coast	n-paraffins	GC	0.28	Clark et al., 1973
	Puget Sound, Wash.	"	"	0.082-3.65	Clar, 1974
Cancer irroratus	Eastern Canada	Aromatics	Fluoro	7	Zitko, 1971
Uca minax		Naphthalene	UV Spec	0.24	Cox & Anderson, 1974
		Methylnaphthalene	"	0.15	"
		Dimethylnaphthalene	"	0.09	"
Sesarma cinereum	Trinity Bay in Galveston Bay	Naphthalenes	UV Spec	0.22	Cox & Anderson, 1974
		Methylnaphthalenes	"	0.10	"
		Dimethylnaphthalenes	"	0.08	"
Lobster					
Homarus americanus					
stomach	Eastern Canada	Aromatics	Fluoro	19	Zitko, 1971
gut	"	"	"	57	"
claw muscle	"	"	"	4	"
abdominal muscle	"	"	"	5	"
Urchin					
Strongylocentrotus sp.	Eastern Canada	Aromatics	Fluoro	22	Zitko, 1971
S. purpuratus	Washington coast	n-paraffins	GC	0.18	Clark, 1974
Flounder					
Syncium gunteri	Gulf of Mexico	n-paraffins	GC	8.7	IDOE, 1972
Unidentified species	Alaska	"	"	8.0	"

Table I-2 (continued)

SPECIES	LOCALITY	HC TYPE	ANALYSIS	WET ug/g	REFERENCE
Pseodopleuronectes americanus	Eastern Canada				
gut		Aromatics	Fluoro	21	Zitko, 1971
skin and flesh		"	"	0	"
Perch					
Sebastes marinus-livers	North Atlantic	Hydrocarbons	GC	110	IDOE, 1972
	George Bank	"	"	20.6	"
Haddock					
Gadus aeglefinus-livers	North Atlantic	Hydrocarbons	GC	210	IDOE, 1972
	George Bank	"	"	252	"
Pollock					
Pollachius verins-livers	Georges Banks	Hydrocarbons	GC	262	IDOE, 1972
Greenland halibut					
Reinhandtius hippo-lossoides-livers	North Atlantic	Hydrocarbons	GC	230	IDOE, 1972
	Gulf of Maine	"	"		
Whitefish-flesh	Alberta, Canada	Diesel oil-like	GC	4-14	Ackman & Noble, 1973
Yellow sole					
Lamanda	Valdez, Alaska	C_{16-28}	GC	0.15-0.97	Kinney, 1973
Herring eggs					
Clupea pallasil	Puget Sound, Wash.	n-paraffins	GC	3.1	Clark, 1974
Cod					
Gadus callarias-livers	North Atlantic	Saturates	GC	128-345	IDOE, 1972
Gadus morhua-livers	"	"	"	332	"
Boreogadus esmarki	"	"	"	117	"
	Arctic Ocean	n-paraffins	"	12.6	Clark, 1974

Table I-2 (continued)

SPECIES	LOCALITY	HC TYPE	ANALYSIS	WET ug/g	REFERENCE
Mackerel *Scomberomorus cavalla*	Gulf of Mexico	n-paraffins	GC	11.3	IDOE, 1972
Barracuda *Sphyraena barracuda*	Texas	n-paraffins	GC	22.6	IDOE, 1972
Atlantic salmon *Salmo salar*	Eastern Canada	Aromatics	Fluoro	10	Zitko, 1971

the authors to be contaminated with petroleum, were in general judged so based on the types of hydrocarbons present, keeping in mind the differences between petroleum and biogenic mixtures. The hydrocarbon types are listed in Table I-1 as indicated by the authors, and though only one class, or a range, of hydrocarbons is given for some samples, it does not exclude the presence of other types of compounds in the sample. Usually the samples analyzed by fluorescence yield low numbers and in most samples the concentration would be much higher if compounds other than polycyclic aromatic hydrocarbons were included. Those samples listing only "paraffins" should also be considered as reflecting a very small part of the total hydrocarbons. This is perhaps especially true for shellfish (Stegeman, 1974).

It is evident that high concentrations of PHC can be found in organisms from spill areas as well as areas of chronic contamination. In many cases, the hydrocarbon level of the waters from which organisms have been taken have not been reported. In other cases, under prolonged exposures, the concentrations could have fluctuated over such a wide range that such information would not realistically reflect the true exposure concentrations. The relative amount of accumulation varies greatly with the organism involved, concentration of hydrocarbon in the water, and composition of the petroleum, etc. On a dry weight basis, the actual amount accumulated can be quite substantial. Di Salvo et al. (1975) reported a preliminary determination of surface hydrocarbons showed the presence of 1.25 ppb while dry weight tissue from mussels, *Mytilus edulis*, exposed for 90 days was recorded as 300 ppm.

In contrast to the PHC concentrations in presumably contaminated organisms, concentrations of hydrocarbons in supposedly uncontaminated populations (Table I-2) are consistently much lower. This is particularly true for the molluscs, where concentrations of 1 to 2 ppm or less are approximately 10 to 100 times lower than those of the contaminated organisms. "Natural" concentrations in some fish and crustaceans appear somewhat higher and in a few cases might be suspect, although these samples were all considered uncontaminated by the authors based on parameters other than the total hydrocarbon content (Anderson et al. 1974).

A striking feature of Table I-2 is that these low levels occur in organisms from all coastal regions of the continent. The concentrations from 0.01 to 10 ppm are the lower limits of analysis based on current techniques and may in many cases represent mostly biogenic compounds. In such cases a few compounds can be expected to constitute the major portion of the hydrocarbon components.

There have to date been a number of studies describing the experimental accumulation of PHC by marine organisms. Table I-3 summarizes results of most of these studies and indicates tissue levels of PHC which can be achieved under a variety of exposure conditions (Anderson et al. 1974). Most of the studies in Table I-3 were performed under static conditions for relatively short periods, i.e. hours to days. The majority used very high exposure levels of emulsions, dispersions, water soluble fractions or slicks ranging from approximately 50 to 10,000 ppm.

These could be taken as partially resembling the situation early in the history of an oil spill. Others were very brief status exposure to single compounds (Lee et al. 1972a), or long term exposure to low levels of whole fuel oil in a flow-through system (Stegeman and Teal, 1973). The last experiment could be considered to represent the conditions of an exposure to chronic sources of contamination in harbors, etc. In fact, the 335 ppm total hydrocarbon accumulated by oysters after seven weeks (Stegeman and Teal, 1973) was not very different from the 236 ppm total hydrocarbons in oysters from the Houston ship channel (Ehrhardt, 1972) shown in Table I-1.

Based on dry tissue weight, Di Salvo et al. (1975) found hydrocarbon concentrations as high as 530 ppm in mussels exposed to low level chronic oil pollution in San Francisco Bay.

3. Storage and Metabolism

Although it has been demonstrated that hydrocarbons concentrate in certain organs, it is actually with the lipids that they become associated (Blumer et al. 1972). Stegeman and Teal (1973) found a direct relation between the lipid content of oysters and the amount of hydrocarbons accumulated. Shipton et al. (1970) reported the dark meat and the fatty layer adjacent to the skin were more severely tainted with a hydrocarbon similar to kerosene than the white meat, and that the tainted flesh had a higher fat content than

Table I-3 Tissue Hydrocarbon Levels Resulting from Laboratory Exposure

SPECIES	EXPOSURE CONDITIONS	HC TYPE	ANALYSIS	WET ug/g	REFERENCE
Clams					
<u>Rangia cuneata</u>	1000 ppm #2 fuel oil, 48 hr	Total saturated	GC	26	Anderson, 1973
		Mono- & diarom.	"	481	"
		Poly aromatics	"	34	"
Mya arenaria	Bunker C	Aromatics	Fluoro	87	Zitko, 1971
Oysters					
<u>Crassostrea virginica</u>	1000 ppm #2 fuel oil. 48 hr	Total saturated	GC	4	Anderson, 1973
		Mono- & diarom.	"	121	"
		Poly aromatics	"	5	"
	1000 ppm #2 fuel oil,	Total saturated	"	3.1	"
		Naphthalenes	"	84.1	"
		Triaromatics	"	9.5	"
	106 ppb #2 fuel oil, 7 weeks	Saturates & arom.	"	335	Stegeman & Teal, 1973
	1000 ppm Kuwait crude, 96 hr	Total saturated	"	46.0	Anderson, 1973
		Naphthalenes	"	55.1	"
		Triaromatics	"	6.0	"
<u>Crassostrea gigas</u>	50 ppm #2 fuel oil, 11 days	Saturated	GC	1.3	Vaughn, 1973
<u>Ostrea lurida</u>	10% outboard motor effluent, 10 days	n-paraffins	GC	0.96	Clark et al., 1974
Mussels					
<u>Mytilus edulis</u>	0.1 ppm mono- & diaromatics 4-24 hrs	Same	Radio.	6	Lee et al., 1972a
	0.1 ppm poly aromatics	"	"	0.6	"
	Slick, #2 fuel oil 48 hrs.	n-paraffins	GC	7.9	Clark & Finley, 1974
	Slick, #5 fuel oil 32 hrs.	"	"	7.4	"
	1C% outboard motor 1 day	"	"	1.10	Clark et al., 1974

(From Anderson et al., 1974).

Table I-3 (continued)

SPECIES	EXPOSURE CONDITIONS	HC TYPE	ANALYSIS	WET ug/g	REFERENCE
Shrimp					
<u>Penaeus aztecus</u>	20% WSF[1] #2 fuel oil, 24 hr.	Sat. (individual peaks)	GC	0.1	Cox & Anderson, 1974
		Nephthalenes	"	0.1	"
		Methylnaphthalenes	"	1.4	"
		Dimethylnaphthalenes	"	0.3	"
		Trimethylnaphthalenes	"	0.6	"
<u>Penaeus aztecus</u>	Underslick of #2 fuel oil for 24 hr in a pond exposure	Saturated Total	GC		Cox & Anderson, 1974
		(C_{13-24})	"	6.2	"
		(C_4-Benzenes)	"	1.2	"
		Naphthalene	"	3.3	"
		1-Methylnaphthalenes	"	8.0	"
		2-Methylnaphthalenes	"	8.9	"
		Dimethylnaphthalenes	"	19.2	"
		Trimethylnaphthalenes	"	4.2	"
		Pheanthrenes	"	12.7	"
<u>Palaemonetes pugio</u>	0.9 ppm OWD[2] #2 fuel oil for 2 hr.	Naphthalenes	GC	3.1	Tatem & Anderson, 1974
	6 hr.	Naphthalenes	GC	5.5	"
	10 hr.	Naphthalenes	UV	4.0	"
Lobster					
Homarus americanus gut	10,000 ppm Bunker C	Aromatics	Fluoro	1,810	Scarrett & Zitko, 1972
stomach	6 1/2 days	"	"	2,840	"
abdominal muscle		"	"	137	"
claw muscle		"	"	33	"

1/ A water-soluble fraction (WSF) was prepared by mixing 1 part oil over 9 parts water for 20 hours, and the water phase was diluted to 20% of its original concentration of hydrocarbons (see Anderson et al., 1974)

2/ Oil was added to water such that 500 ml contained 0.9 ppm of oil. This mixture was shaken at 200 chcles/min. for 5 min. and after 60 min. the animals were placed in the mixture.

Table I-3 (continued)

SPECIES	EXPOSURE CONDITIONS	HC TYPE	ANALYSIS	WET ug/g	REFERENCE
Perch					
Cymatogaster aggregata	50 ppm #2 fuel oil,	Saturated	GC	2.3	Vaughn, 1973
	96 hr	Diaromatics	"	19	"
Flounder					
Pseudopleuronectes	Bunker C				
americanus Gut		Aromatics	Fluoro	622	Zitko, 1971
skin		"	"	182	"
flesh		"	"	7	"

the untainted flesh of fish caught at the same time. Vale et al. (1970) examined livers with optical and electron microscopes and found excessive amounts of free fat, typical of fatty infiltration, in tainted fish as compared with untainted mullet. Fatty liver in higher animals can be caused by petroleum distillates (Browning, 1953).

Roubal (1973), working with excised spinal cord tissues of coho salmon, indicated that hexane and similar hydrophobic compounds are directed away from nerve membrane surface to sites in the lipid bilayer of the membrane, while aromatic hydrocarbons and benzyl alcohol contribute to membrane surface changes. The complex lipoproteins of plasma membranes and organelle membranes of all tissues are possible storage sites (NAS, 1975).

According to a summary paper by Anderson et al. (1974a), accumulated petroleum hydrocarbons are rapidly transferred to the gall bladder, brain and other neural tissues, and the liver of fish and to the digestive gland of shrimp. Damage to fish having concentrations of petroleum hydrocarbons in the nervous system can be seen as an increase in nonadaptive behavior responses.

Lee et al. (1972b) and Anderson et al. (1974a) found localization of hydrocarbons in the gall bladder, liver, and brain of marine fish. During depuration in clean water the hydrocarbons were apparently transported to the liver and gall bladder for detoxification and excretion. A significant amount of contamination remained in the heart and brain until the point of final release. Since the compounds are transported by the blood, it is not surprising that the concentration in the heart is high, but an explanation for high levels in the brain requires further investigation.

Cox and Anderson (1974) reported that brown shrimp, *Penaeus aztecus*, accumulate the naphthalene fraction of hydrocarbons primarily in the digestive gland or hepatopancreas throughout the exposure period. The content of these compounds in the other organs and tissues decreases steadily, even during exposure. The gill tissue maintains a relatively consistent level of contamination (approximately 0.6 ppm) during the depuration until the point of final release by the digestive gland (about 250 hours). Since the gills are richly supplied with blood, the contamination level found may well represent contamination level in the blood of the shrimp.

Scarratt (1971) reported commercial species of scallops which had ingested Bunker C oil had a detectable amount of Bunker C hydrocarbons in the mantle, digestive gland, adductor mussel and gonad. Di Salvo et al. (1975) reported hydrocarbons in the gonads of mussels. Operation Oil (1970) reported that oil was present in the muscle tissue, digestive tract and other organs in scallops, periwinkles, sea urchins, and other intertidal benthos examined after Bunker C oil had been spilled in the *Arrow* accident. Blumer and Sass (1972a) also reported hydrocarbons in adductor muscles of oysters after the West Falmouth spill.

The danger to the human consumer from PHC-contaminated sea food is lessened because hydrocarbons are primarily concentrated in certain organs such as the liver, gall bladder, and much of the nervous system which are discarded prior to consumption. The danger to humans who consume contaminated oysters, which are eaten in their entirety, would be significantly greater. Apparently some danger of oil contamination can occur from eating other molluscs which may have accumulated oil in muscle tissue.

Metabolism of hydrocarbons is discussed in the summary paper by the National Academy of Sciences (1975).

> The metabolic pathways involving oxidases and other enzymes, important in the degradation of aromatic and paraffinic hydrocarbons by mammalian systems, have been well studied. In the case of aromatic hydrocarbons, hydroxylation is followed by conjugation with sulfate or glucose and finally excretion of the water-soluble product. Straight chain hydrocarbons are hydroxylated at the terminal end and further oxidized to the fatty acid that can be broken down by b-oxidation. Highly branched chain hydrocarbons, such as pristane and phytane, are probably oxidized to an acid (e.g. phytanic acid), which can be further oxidized by a combination of a and b oxidation.

Metabolism of hydrocarbons in marine organisms is less well understood, but several studies have been conducted. Degradation of sizeable quantities (between 10 and 500 ug) of aromatic and paraffinic hydrocarbons did occur in marine fish and some marine invertebrates (Stegeman and Teal, 1973; Lee et al., 1972a,b). Other benthic marine invertebrates, phytoplankton, and some zooplankton, over a period of a month, were unable to oxidize either paraffinic or aromatic

hydrocarbons. Several species of copepods were unable to metabolize hydrocarbons but could degrade paraffinic hydrocarbons (National Academy of Science, 1975). The liver or the liver-like organ in some invertebrates, the hepatopancreas, is assumed to be the site of hydrocarbon degradation. Unaltered hydrocarbons are sent to these organs where hydroxylation and other detoxification reactions occur. In those invertebrates where degradation does not occur, some of the detoxifying microsomal oxidases in the hepatopancreas may be missing.

A somewhat less efficient and slower hydrocarbon metabolizing system has been reported in crustaceans (Anderson et al., 1974a). Studies with molluscs have failed to demonstrate the presence of any hydroxylase activity (Carlson, 1972a) also failed to observe formation of metabolites of hydrocarbons by mussels.

According to Anderson et al. (1974a)

> Though it is clear that levels accumulated vary with exposure conditions, some generalizations can be made: (1) In all types of exposures high levels of PHC can be found in the organisms. Here again the listing of only one type of hydrocarbon does not mean that other types of hydrocarbon were not present. In fact, the identification of only saturated compounds may yield numbers much lower than the total PHC present. (2) Mono-aromatics and diaromatics appear to be more readily accumulated than either saturated compounds or PAH. In addition, long term exposure results indicate that changes in the composition of the retained hydrocarbons, especially a relative decrease in paraffins, occur throughout the exposure period. (3) It appears that the muscle tissue of fish and crustaceans accumulate relatively low levels of hydrocarbons. With the exception of molluscs which are entirely consumed by man, muscle is generally the edible portion of marine organisms.

4. Discharge or Depuration of Hydrocarbons

Throughout the relatively short period since studies on oil accumulation in aquatic organisms began, evidence confirming and denying the ability to depurate accumulated hydrocarbons has been presented.

Blumer et al. (1970) reported that when oysters *Crassostrea virginica* are exposed to water-oil mixtures, they nonselectively accumulate a wide variety of PHC in their tissues which are retained for several months or perhaps indefinitely.

Results from Blumer and Sass (1972b) study on highly aromatic No. 2 fuel oil suggest that oil becomes part of the organism's lipid (fatty) pool. Blumer noted that the oil in specimens observed from a Massachusetts oil spill remained relatively unchanged in composition or quantity. He reasoned that if the oil were localized within the digestive tract, a shellfish could eliminate it rapidly. But the persistence of the hydrocarbon over a time period of six months, its presence in adductor muscle tissue, and the lack of further degradation of these hydrocarbons indicated that it becomes part of the organism's lipid pool.

Lee et al. (1972a) exposed the mussel *Mytilus edulis* to isotopically labeled petroleum-derived alkanes and aromatic hydrocarbons and showed that the molluscs released more than 90% of the accumulated hydrocarbons within two weeks of return to isotope free sea water.

Simulating the conditions of an oil spill, Anderson et al. (1974a) have presented evidence that estuarine fish and macroinvertebrates completely depurate accumulated hydrocarbons after short term exposures of four days or less.

Anderson (1973) presented the detailed hydrocarbon composition of clam *Rangia cuneata* and oyster *Crassostrea virginica* tissue exposed to crude and refined oils for periods up to four days. The subsequent release of HC's accumulated from No. 2 fuel oil and South Louisiana crude oil by oysters was also reported. The levels of tissue contamination decreased to less than detectable concentrations (0.1 ppm) in from 24 to 52 days (Figure I-2). The aromatic hydrocarbons were accumulated to the greatest extent and retained the longest in these studies.

Anderson and Neff (1974b) have shown comparative data for the uptake and release of naphthalenes from No. 2 fuel oil by clams, fish, and shrimp. While approximately 0.8 ppm of total naphthalenes was still present in the clams *Rangia cuneata* at 360 hours, the fish *Fundulus similis* and shrimp *Penaeus aztecus* had released the hydrocarbons to background levels. It is interesting that even during the 24 hours of exposure the concentration in shrimp tissue dropped from about 70 ppm at 1 hour to approximately 3 ppm of total naphthalenes after 24 hours.

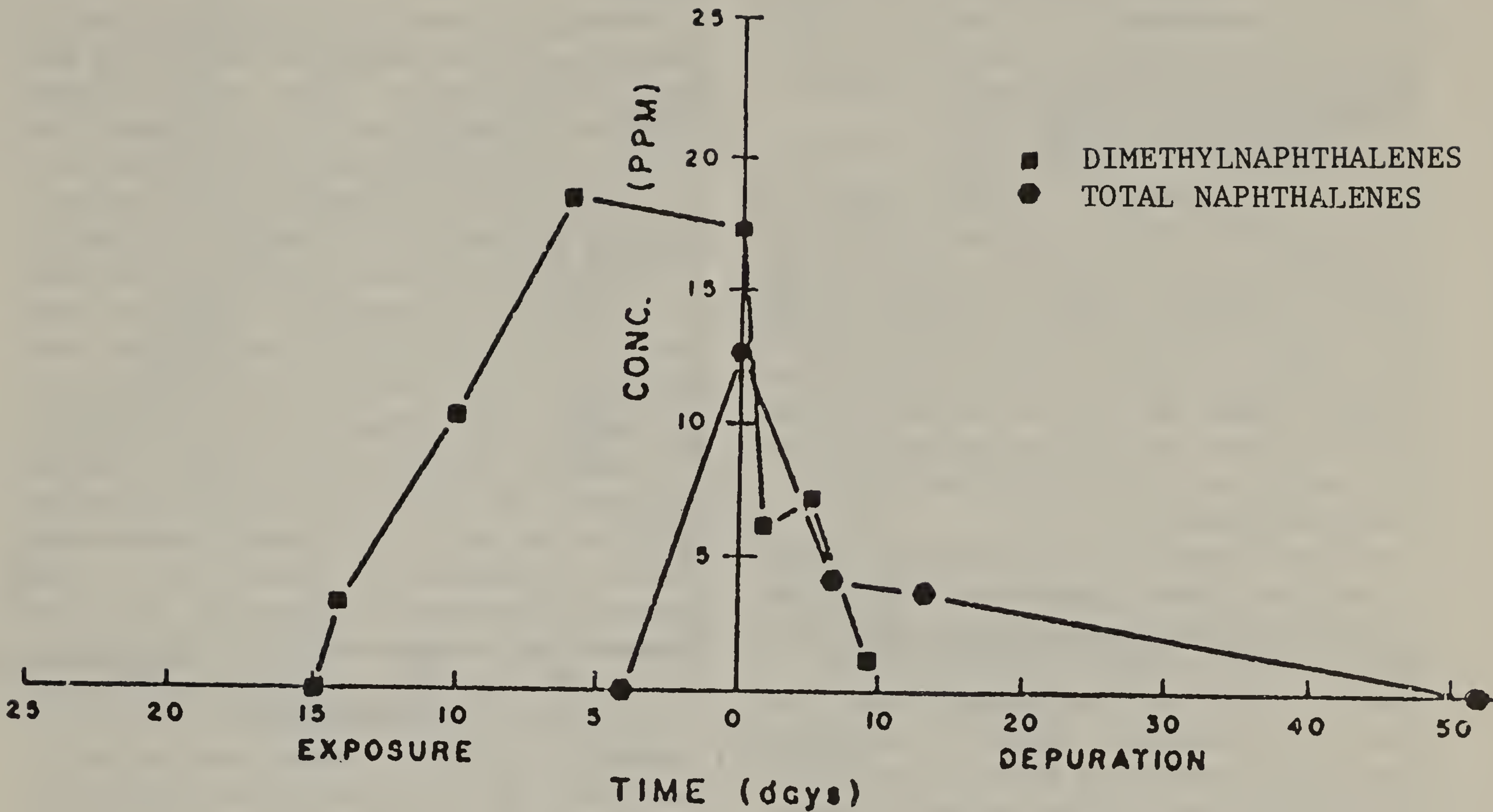


Figure I-2 Levels of petroleum hydrocarbons in the tissues of marine organisms after various periods of exposure and depuration (in clean water). The levels of dimethylnaphthalenes in the tissues of Pacific oysters exposed to 50 ppm of South Louisiana crude oil (Vaughan, 1973); exposure of the American oyster, Crassostrea virginica, to an oil-water dispersion of #2 fuel oil total naphtalenes (Anderson, 1973). All data are expressed in µg/g fresh weight of organisms (ppm). (From Anderson et al. 1973).

Further evidence of the importance of naphthalenes in the contamination of the marine organisms is shown by the work of Vaughan (1973). During 15 days of exposure to oil, Pacific oysters were found to accumulate significant amounts of dimethylnaphthalenes. On removal from the contaminated water, the tissue content of dimethylnaphthalenes decreased to a level slightly above the background within nine days in clean flowing sea water (Figure I-2).

It should not be assumed that only aromatic HC's are accumulated by marine animals, as Clark and Finley (1974) have demonstrated uptake of paraffins by mussels *Mytilus edulis* reaching a level of 112 ppm dry weight (7.9 mg/g wet weight) after 48 hours of exposure to No. 2 fuel oil. While the majority of these accumulated HC's were released during the first two weeks of maintenance in clean sea water, approximately 6 ppm (dry weight) was present at 14 and 35 days of depuration (Figure I-3).

Mussels collected at Scripps showed a buildup of petroleum hydrocarbons for several days after a fuel oil spill. But three weeks later, none of the material could be found in the mussels (Lee and Benson, 1973). Fish from Alaskan waters were able to completely depurate accumulated hydrocarbons after short term exposures (Rice, 1975). Several studies either designed to simulate chronic oil pollution or actually conducted in chronic field conditions, have indicated that, although over 90% efficient, molluscs do not completely depurate accumulated hydrocarbons.

Stegeman and Teal (1973) exposed oysters, *Crassostrea virginica*, to No. 2 fuel oil at a concentration of 106 ug/l (ppb) for 50 days. In terms of total wet body weight, hydrocarbon accumulation increased rapidly for 13 days, then more slowly until equilibrium was reached in five to six weeks. In terms of lipid content, equilibrium was not reached during the 50 day exposure period. The amount of accumulation was dependent upon the fat content of the oysters, reaching 334 mg/g (ppm) in high fat oysters but only 161 mg/g (ppm) in low fat oysters. When placed in clean water having a background hydrocarbon level of 11 ug/l (ppb), oysters depurated 90% within the two week holding period, but retained a concentration of 34 mg/g (ppm), a concentration of over 30 times that before exposure (Figures I-3 and I-4). They concluded that at least some of the PHC had become a stable component having a slow turnover rate. There is a physiological advantage for marine organisms to avoid loss by equilibration of important biogenic hydrocarbons, and a certain amount of petroleum hydrocarbons were probably confused with biogenic hydrocarbons and retained this way.

Working with mussels, *Mytilus edulis* and *M. californianus*, in the natural environments of polluted (San Francisco Bay) and unpolluted (Northern California coast) areas, Di Salvo et al. (1975) reported incomplete depuration when mussels held in polluted areas for 90 days were transferred to nonpolluted areas and held for 10 weeks.

The evidence indicated there may be two forms of hydrocarbons accumulation in bivalve molluscs; (1) A short-term form where PHC are taken up rapidly and depurated completely or to background levels within several weeks to two months (Lee and Benson, 1973; Rice, 1975 and Anderson et al., 1974a). This reflects the response during an oil spill. (2) A long-term hydrocarbon burden accumulated in tissues that is not completely discharged (Blumer et al., 1970; Blumer, 1969; Stegeman and Teal, 1973; Di Salvo et al., 1975). This reflects chronic oil pollution exposure when primarily aromatic hydrocarbons are accumulated in lipids. A similar residual hydrocarbon burden may be present in certain species of zooplankton, if it is possible to expose them to oil for a long enough period.

Because they apparently have the ability to metabolize hydrocarbons, shrimp, fish, and marine mammals would probably not retain the residual hydrocarbon concentration as do the molluscs.

The National Academy of Sciences (1975) reported on the avenues of depuration of accumulated hydrocarbons. In molluscs and certain zooplankton which cannot degrade hydrocarbons, bile salts or some other natural detergents are able to emulsify hydrocarbons and allow passage through the gut and into the feces or pseudofeces. Fish make water soluble products from the hydrocarbons, and the main avenue of discharge appears to be through the urine via the gall bladder and kidney. In mammals, aromatic hydrocarbons are also converted to water soluble products that go through the bile and into the feces and urine. The avenue for the discharge of hydrocarbons by the lobster and related invertebrates has not been determined.

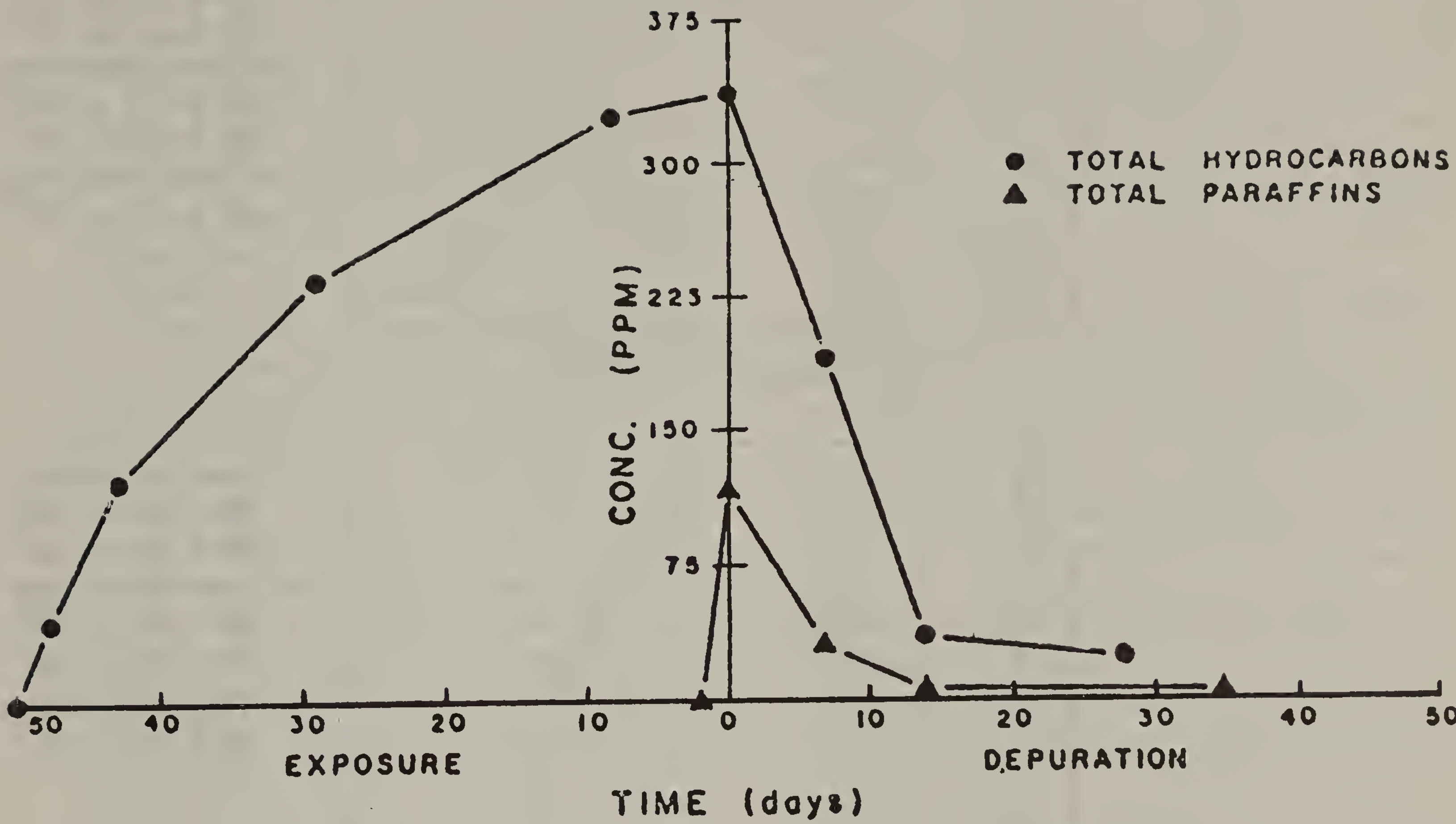


Figure 1-3 Levels of petroleum hydrocarbons in the tissues of marine organisms after various period of exposure and depuration (in clean water). Exposure of oysters to #2 fuel oil in a flowing system at a concentration of 106 ppb total hydrocarbons (Stegeman and Teal, 1973); the mussel, Mytilus edulis, exposed for 48 hours to surface oil slick total paraffins (Clark and Finley, 1974). With the exception of the data points for Mytilus which are expressed in µg/g dry weight of tissue, all additional data are expressed in terms of µg/g fresh weight of organism (ppm). (From Anderson et al. 1973).

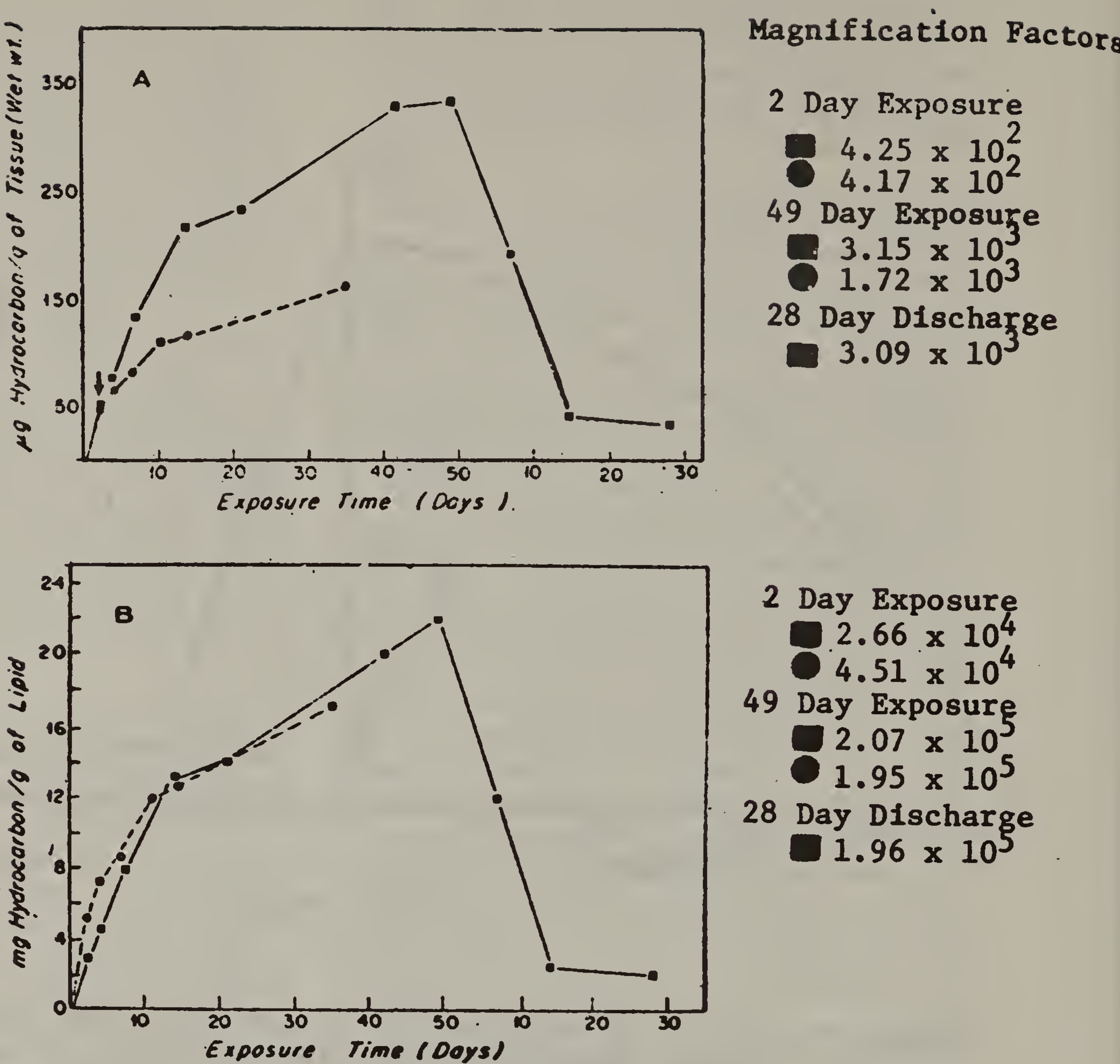


Figure 1-4 Crassostrea virginica. Uptake and release of petroleum hydrocarbons by high fat-content (squares) and low fat-content (circles) oysters. Concentration of hydrocarbons expressed on (A) wet-weight basis, (B) lipid basis. The concentration of hydrocarbons in the water was 106 μg/l. At Day 50, high fat-content oysters were transferred to system with 11 μg hydrocarbon/l water. Each point represents determination of hydrocarbons in 3 oysters, with determinations in duplicate samples of three at Days 2 and 14. Magnification factors refer to concentration in the water. Concentration in low-fat oysters at Day 49 was determined by extrapolation. (From Stegeman and Teal, 1973).

Di Salvo et al. (1975) mention that another potential for the release of hydrocarbons may be in the eggs which, in mussels, were found to be enriched particularly with aromatic hydrocarbons compared to the total body concentration.

The present knowledge of depuration of petroleum hydrocarbons in marine animals is summarized by Anderson et al. (1974a).

> It would seem that reduction of a body burden of hydrocarbons by metabolisms could have possible significance in fish, but probably not crustaceans or molluscs. As indicated above, however, all three groups are capable of disposing of accumulated PHC. The mechanisms responsible for disposal have yet to be clearly defined, particularly for crustaceans and molluscs, and for all three groups the real extent to which disposal occurs by release across gill membranes is still an unanswered question. With fish, where metabolism is a distinct possibility, there is information for only a few species and that very cursory. Rates of PHC metabolism in vivo under various environmental conditions are at this point impossible to guess. Furthermore, in terms of the consumer, we have no information regarding what percentage of PHC metabolites, some of which may be toxic, are retained or excreted by fish under varied conditions.

5. Food Web Magnification

There is increasing evidence that classical food web magnification (an increasing concentration of hydrocarbons per weight of tissue or lipid at successively higher trophic levels) of petroleum hydrocarbons does not occur. The principal evidence for this is: (1) Organisms so far tested have the ability to depurate at least the majority of accumulated hydrocarbons. Food chain magnification is dependent upon long term retention of the pollutant in tissues. (2) Much of the hydrocarbon ingested by zooplankton and other organisms passes through the gut without ever becoming accumulated into the body tissues. (3) The most important method of hydrocarbon accumulation is apparently transference across the gill surface. According to the National Academy of Sciences (1975) "Apparent food chain magnification may more likely be a function of the ability of different species to accumulate hydrocarbons from the water than a function of their position in the food web."

The possibility exists of some selective hydrocarbon buildup in the food chain in chronically polluted areas through molluscs which retain a portion of the toxic aromatic hydrocarbons. Although magnification would not occur, greater than normal levels of aromatic hydrocarbons could be passed on to the next trophic level. The resultant damage to the predator is not known, but would depend upon the concentration of aromatics in the prey, frequency of consumption, and toxicity or carcinogenicity of the particular aromatic hydrocarbons with the tissue of the prey organism.

The fact that the animals tested do accumulate hydrocarbons in rather large quantities in a relatively short time indicates that temporary food chain buildup can occur. The naphthalenes, which are among the most toxic petroleum fractions, remain within the prey species the longest (Anderson et al., 1974a). The carcinogen benzo-a-pyrene acts similarly to naphthalenes in animal tissues. If the temporary accumulation of naphthalenes and/or benzo-a-pyrene reached high enough concentrations in predators, death or cancer could result. The impacts would be of far shorter duration and of less impact on the marine ecosystem than if the classical food web buildup did occur.

There are other nonhydrocarbon components of oil (including but not limited to those discussed in Section 1) which could be magnified through the food web. Very little information is available for many of these compounds and, although most occur in small concentrations, the long range effects are not completely understood.

Another possible implication of oil spills in the marine environment is a decrease in the available food supply due to the death of prey species which have succumbed to the toxic fractions of oil. A detailed discussion of this factor is beyond the scope of this paper.

6. Microbial Decomposition

A necessary part of the food cycle in all systems is the decomposition of organic matter. Decomposition of petroleum hydrocarbons will be briefly discussed.

According to the report by the National Academy of Science (1975),

> It must be emphasized that with this multivariable system it is impossible to predict with either ease or accuracy the rate of microbial oil

removal. Few reliable field measurements have been made in the marine environment (Blumer et al., 1972c; Robertson et al., 1973); laboratory experiments, in which conditions, are optimal for oxidation can only give some indication of maximum rates. Even under laboratory conditions, the various fractions of oil or oil products will disappear at rates that can be measured on a time scale of weeks in some instances and that are immeasurable slow in others. Environmental stresses such as temperature and salinity changes, wave action, and sunlight not only directly affect the growth and metabolism of the microorganisms but also alter the physical state (for example, emulsification) and ultimately the chemical nature (for example, oxidation) of the hydrocarbons.

In sediments, chemical degradation of oil can occur but is restricted to the layer of the bottom penetrated by ultraviolet light. Ahearn and Meyers (1973) stated that research on microbial utilization of hydrocarbons for treatment of oily pollutants in the environment, though more intensive in recent times, is still in an early stage of development. It is known that microorganisms can degrade much of a crude oil, particularly the less toxic paraffinic compounds. No single species can degrade all the compounds, but many different species together can metabolize a large number of the compounds.

Microbial degradation is principally aerobic and large quantities of oxygen are needed. It has been estimated, for instance, that complete oxidation of 1 gallon of crude oil would require all of the dissolved oxygen in 320,000 gallons of water. It is reasonable to assume, however, that an oxygen deficient environment could occur under some oil slicks and in oil contaminated sediments. Much of the oil from the Santa Barbara blowout, for example, is believed to have settled in the Santa Barbara Channel (Battelle Northwest, 1970) where oxygen is already deficient and is probably insufficient for further decomposition.

Blumer and Sass (1972b) noted that "The preservation of hydrocarbons in marine sediments for geologically long time spans is one of the accepted key facts in current thought on petroleum formation." However, in spite of the stability of hydrocarbons in marine sediments, there are characteristic differences between hydrocarbons found in polluted and unpolluted areas. Tissier and Oudin (1973) found that hydrocarbons in polluted sediments differed from those of unpolluted sediments by having lower percentages of heavy components having an odd carbon dominance in the n-alkanes, and having polycyclic aromatic hydrocarbons with alkyl sidechains.

Numerous intermediates and end products have been identified in laboratory experiments (Friede et al., 1972; Klug and Markovetz, 1971), some of which may be disruptive to chemotaxic mechanisms of marine forms (Mitchell et al., 1972; Zafiriou, 1972). The microorganisms that digest oil may be pathogenic or produce toxins (Traxler, 1973).

The influences of environmental factors on decomposition rates has been summarized by the National Academy of Science (1975) report.

Temperature increases may accelerate growth rates, thereby increasing biodegradation (Friede et al., 1972; ZoBell, 1973). A rise in temperature also increases the rate of evaporation of more volatile components, some of which are degradable and some of which are toxic (Atlas and Bartha, 1972b; see also previous section). Viscosity is lower at higher temperatures, thereby increasing the chance of emulsification and increasing the surface area available for microbial activity and solubility (ZoBell, 1973). Temperature decreases may not necessarily reduce the overall rate of microbial biodegradation significantly if special psychrophilic cultures develop (Robertson et al., 1973; Traxler, 1973).

Oxygen content is probably always sufficient for degradation of oil at the surface layer and in the upper water column in the open ocean (Friede et al., 1972). The degree of turbulence directly affects the availability of oxygen, as well as the physical dispersion and emulsification of the oil. If the water or sediments become anoxic, then rates of biodegradation will be markedly reduced (Davis, 1967).

Nitrogen and phosphorus concentrations strongly influence the rate of oxidation in laboratory experiments (Gunkel, 1967, 1968; Atlas and Bartha, 1972a). These nutrients may more commonly be limiting in the open oceans than in inshore regions.

Numerous other factors influence biodegradation, for example, presence of sufficient hydrocarbon substrate to develop a viable culture, presence of alternative carbon sources and microbial predators (Gunkel, 1968; Friede et al.,

1972), but data are generally insufficient to precisely determine in situ effects on microbial oil utilization.

7. Carcinogenicity

As far as man is concerned, some doubt remains as to the direct carcinogenicity of crude oil and crude oil residues in marine organisms.

A literature search and evaluation conducted for the U.S. Coast Guard by Batelle Memorial Institute (1967) noted that shellfish, although alive, may have been unfit for consumption because of the carcinogenic hydrocarbon 3, 4-benzopyrene in their bodies. Oysters that were heavily polluted and contaminated with ship fuel oil were reported to contain 3, 4-benzopyrene. The Batelle review also reported that barnacles attached to creosoted poles contained the same carcinogenic hydrocarbon. Sarcomas were developed when extracts from the barnacles were injected into mice.

The carcinogenic benzo-a-pyrene behaves similarly to naphthalenes in pattern of uptake, retention, and release in clams (Anderson and Neff, 1974). As indicated earlier, they reported that organisms accumulated naphthalenes in tissues in greater amounts than the other hydrocarbons and released them more slowly.

Hyperplasia (increase in the rate of cell division) in reproductive cells of bryozoan in response to the addition of coal tar derivatives was reported by Powell, et al. (1970).

They noted that similar abnormalities may have occurred in coastal fauna exposed to spills such as the *Torrey Canyon* and the Santa Barbara blowout. However, most observations of these spills were concerned with mortality and may not have detected the sublethal effects. Straughan and Lawrence (1975) investigated the response of a number of bryozoan species to exposure to natural oil seepage, but found normal cell formation.

ZoBell (1971) reported the natural synthesis and metabolism of carcinogenic hydrocarbons by several marine organisms. Thus, oil pollution is certainly not the only source for carcinogenic hydrocarbon introduction into marine food webs. Suess (1972) recognized that carcinogens were in seafoods but concluded that they would probably not be dangerous unless the foods contained an excess amount of polynuclear aromatic hydrocarbon carcinogens. Carcinogenesis from oil contaminated marine organisms has not been proven, but Ehrhardt (1972) expressed a need for carcinogenic testing of hydrocarbon fractions extracted from marine organisms contaminated by exposure to oil.

According to the National Academy of Sciences (1975) workshop on petroleum in the marine environment:

> Although our information is limited, the effect of oil contamination on human health appears not to be cause for alarm. From our calculation, we estimate that the carcinogen benzo-a-pyrene concentration on a dry weight basis arising from a high level of contamination by petroleum is comparable with that of common terrestrial foods. We, of course, do not recommend eating contaminated seafood, but in most cases, because of the taste factor, not many will be tempted to do so. It is clear that this is an area in which our knowledge is grossly inadequate and that the contamination of seafood by oil is clearly undesirable.

Recent work by Yevich, of the National Marine Water Quality Laboratory in Naragansett, Rhode Island, has further implicated petroleum as a carcinogen. During two oil spills involving No. 2 fuel oil and a No. 5 diesel oil, he found two types of cancer in soft shell clams. One type forms in gonadal tissue and quickly spreads to other organs, while the other is a blood cell form similar to leukemia (Yevich, in press).

If Yevich's results prove to be valid, there should be greater cause for alarm than indicated by the National Academy of Science report.

8. Heavy Metals

a. Natural occurrence and sources from offshore petroleum operations

Heavy metals occur naturally in sea water in relatively low concentrations. Table I-4 lists average background concentrations in the open ocean for several heavy metals that have been associated with offshore petroleum operations. The residence time of the metal ions and their complexes is an estimate of turnover time in the marine environment. It must be emphasized that there are many dynamic physical and biological processes in the ocean that continually affect these "average" concentrations. Generally the concentrations in Table I-4 would be applicable to the open ocean area away from the direct influence of the coastal zone. In the coastal zone, especially in estuaries, near river mouths and in areas of high levels of industrial or municipal

Table I-4 Background Concentrations of Most Heavy Metals in the Ocean

Element	Seawater conc. ug/1 (ppb)	Principal Dissolved Species	Residence Time in Ocean (Years)
- V	2	$VO_2\ (OH)^{-2}$	8.0×10^4
- Cr	0.5	CrO_4^{-2}, Cr^{+3}	2.0×10^4
- Mn	2	Mn^{+2}	1.0×10^4
- Fe	3	-	2.0×10^2
- Co	0.4	Co^{+2}	1.6×10^5
- Ni	7	Ni^{+2}	9.0×10^4
- Cu	3	Cu^{+2}	2×10^4
- Zn	10	Zn^{+2}	2×10^4
- As	2.6	$HAs\ O_4^{-2}$	5×10^4
		$H_2As\ O_4^{-1}$	
- Cd	0.1	Cd^{+2}	-
- Ba	20	Ba^{+2}	4×10^4
- Hg	0.2	$Hg\ Cl_4^{-2}$,	8×10^4
		$Hg\ Cl^o_2$	
- Pb	0.03	Pb^{+2}	2.0×10^3
- Ag	0.04	Ag^{+1}	2.1×10^6

Modified from: Goldberg et al. (1971)

discharges, the concentrations can be several times higher.

Natural sources of heavy metals to the ocean are river water, wind blown material from land following the weathering of rocks and tectonically active ridges where heavy metals are emitted in heavy brines. In coastal regions, additional major sources of heavy metals include sewage discharges, industrial effluents and atmospheric pollution. As an example of the atmospheric source, Patterson and Settle (1974, as cited by NSF/IDOE, 1974) found that atmospheric particle input is a major source of industrial lead in the Southern California Bight, comparable to the input of lead from storm runoff, rain and sewage. The atmospheric lead originates from cars burning leaded gasoline.

Many heavy metals in trace amounts are essential for animal and plant life. At present 14 trace elements are known to be essential for animal life: iron, zinc, copper manganese, cobalt, iodine, molybdenum, selenium, chromium, tin, nickel, fluorine, silicon and vanadium. These elements serve as components of enzymes or enzyme systems, enzyme activators, and components of vitamins, hormones and respiratory pigments. A few heavy metals such as arsenic, lead, cadmium and mercury are often referred to as toxic elements since they are toxic to marine organisms at relatively low concentrations and have no other known biological significance (Underwood, 1974). However, any of the heavy metals normally accumulated by marine organisms can be toxic if they are ingested or taken up at sufficiently high levels for long enough periods. Heavy metals and other trace metals in marine organisms are held by strong chemical bonds and are not readily released into the marine environment (Goldberg, 1965).

Offshore petroleum operations are potential sources of heavy metals to the coastal waters. Heavy metals are present in petroleum, formation waters (oil field brines) and drilling fluids. Crude oils vary greatly in trace element composition, and variations in trace element groups can occur from well to well in a particular geological formation (Filby and Shah, 1971). Concentrations of heavy metals and other trace elements in several crude oils are presented in Table I-5. Nickel (Ni) and vanadium (V) are generally the most abundant metallic elements in crude, but as shown in Table I-5, cobalt (Co), mercury (Hg), iron (Fe) and zinc (Zn) can be abundant in some crudes, in this case California crude. According to Filby and Shah (1971), very little is known of the forms of occurrence of trace elements other than Ni and V in crude oil. Ni and V occur partly as porphyrin complexes and partly in non-porphyrin type compounds associated with the high-molecular-weight material of the oil. The resins and aspahltenes contain most of the trace elements. These groups are not definite classes of compounds but are colloidal materials covering broad molecular-weight and polarity ranges (Filby and Shah, 1971).

Formation waters contain heavy metals in various concentration ranges. Formation waters are either discharged into the ocean after separation of oil fractions or reinjected into formation reservoirs. Median concentrations of various trace metals in formation waters are given in Table I-6.

Drilling muds used during drilling operations may be discharged periodically or accidentally into the ocean. Because of this, concern has been expressed over the introduction into the marine environment of toxic substances since the two major components of drilling mud are barite (barium sulfate) and ferrochrome lignosulfonate which contain the elements barium and chromium, known to be toxic in certain of their elemental states. A recent conference on the environmental aspects of chemical use in well-drilling operations in May, 1975 in Houston, Texas addressed these and other problems. The following information can be found in the report of the conference.

Barium sulfate, used as a weighting agent during drilling, is also used as a contrast medium for roentgenographic purposes and as an antidiarrheal and demulcent powder. Toxicity studies using *Mollienisias latipinna* (mollies) show that heavy concentrations of barium sulfate (up to 100,000 ppm for 96 hrs) exhibit no toxicity to fish (Grantham and Sloan, 1975).

Another report shows low toxicity but some physical problem with *Salmo salar*, Atlantic salmon because of suspended solids (Zitko, 1975). Concentrations of these magnitudes would exist only at the point of discharge.

Ferrochrome lignosulfonate is used as a deflocculant or thinning agent in drilling muds. Whereas chromium itself is highly toxic to certain species, when bound it is less toxic (Zitko, 1975) and it has been shown that in ferrochrome lignosulfonate the chromium is firmly chelated and may

Table I-5 Trace Element Contents of 6 Crude Oils[a]

Elemental Conc (ug/g)[b]	Oil Number					
	RF-1	RF-2	RF-3	RF-4	RF-5	RF-6
Ni	93.5	113.0	78.6	116.8	1.28	20.5
V	7.5	6.0	4.9	112.0	26.0	8.2
Co	12.7	13.9	14.5	0.198	0.001	0.0354
Hg	21.2	1.49	1.46	0.139	0.0143	0.0898
Fe	73.1	77.2	89.5	36.9	<5.0	4.94
Zn	9.32	19.50	19.60	2.619	<0.0907	9.08
Cr	0.634	0.685	0.729	0.380	<0.1	0.081
Mn	2.54	3.10	2.96	0.21	<1.50	0.79
As	0.656	1.63	0.67	1.20	<0.2	0.0773
Au	2.8×10^{-6}	......	....	3.0×10^{-6}	$<10^{-7}$	6.4×10^{-5}
Sb	0.0517	0.061	0.11	0.273	$<10^{-3}$	0.055
Se	0.364	0.484	0.333	0.369	0.009	0.128
Sc	8.8×10^{-3}	9.0×10^{-3}	4.6×10^{-3}	4.4×10^{-3}	9.5×10^{-5}	$<10^{-5}$
Cu	0.93	1.25	1.13	0.21	<0.2	0.19
Na	11.1	65.2	15.5	25.0	<1.0	13.0
Ca	192.0	75.1	103.0	150.0	<20.0	<20.0

[a]Oils RF-1, 2, 3 from California; RF-4, Venezuela; RF-5, Louisiana and RF-6, Libya

[b]Conc = concentrations in ppm

From Filby and Shah (1971)

TABLE I-6. MEDIAN CONCENTRATION OF TRACE METALS IN PRODUCED WATERS[1]

Median Concentration (equaled or exceeded by 50% of the samples) in Each Area[2]

	Number of Samples	Total Solids (madian) (g/1)	Co	Cr	Cu	K	Li	Mg	Mn	Ni	Sn	Sr	Ti	V	Zr
Illinois Basin	22	98	ND	2p	10p	300	15	6,000	175p	ND	< 1p	300	<10p	ND	<10p
Louisiana and Texas Gulf Coast	79	69	ND	<1p	<25p	300	ND	250	3.5	<1p	< 1p	85	<10p	ND	<10p
East Texas	88	66	ND[3]	ND	< 1	<50	ND	250	3.3	<1p	3p	350	ND[3]	ND[3]	ND
North Texas	24	222	ND	<1p	150p	300	ND	5,000	45	15p	12p	450	7p	ND	<10p
West Texas and New Mexico	148	111	ND	2p	1p	350	15	1,000	1.8	<1p	< 1p	200	<10p	ND	ND
Permian only	74	143	ND	2p	2p	400	10	1,000	1.7	<1p	< 1p	90	<10p	< 1p	ND
Pennsylvania only	34	115	ND	3p	< 1p	300	10	1,000	2.8	<1p	< 1p	300	<10p	< 1p	ND
Silurian-Devonian only	15	55	ND	2p	4p	300	10	400	300p	<1p	1p	90	<10p	ND	ND
Ordovician-Cambrian only	21	67	ND	<2p	4p	400	15	800	400p	<1p	1p	250	<10p	ND	ND
Anadarko Basin[4]	118	137	ND	10p	10p	250	10	1,550	5.6	6p	2p	300	<10p	< 1p	<10p
Williston Basin, post-Paleozoic	25	59	<5p	<2p	<25p	300	ND	250	300p	<3p	< 1p	100	ND	< 1p	ND
Williston Basin, Paleozoic	55	173	ND	3p	3p	800	35	600	660p	ND	< 1p	95	<10p	< 1p	ND
Powder River Basin	22	5	<5p	<2p	<25p	300	ND	40	450p	<3p	< 1p	25	<10p	< 1p	<10p
Other Wyoming	28	5	ND	ND	ND	300	ND	100	300p	ND	< 1p	20	<10p	< 1p	ND
Colorado	18	5	<5p	ND	<25p	300	ND	30	300p	<3p	<10p	20	<10p	< 1p	<10p
California	116	18	ND	5p	5p	45	ND	90	950p	10p	2.5p	10	<10p	< 1p	ND
Seawater	-	35	0.27p	0.04p-0.07p	1p-15p	380	0.1	1,272	1p-10p	5.4r	3p	13	Present	0.3p	ND
Estimated Detection Limit	-	-	1p	1p	1p	50	2	10	1p	1p	1p	16	10p	1p	10p

1/ Taken from Rittenhouse, Fulton, Grabowski, and Bernard

2/ ND = below detection limits; p = concentration in parts per billion, otherwise parts per million

3/ No data; less sensitive methods of analysis used.

4/ Includes Oklahoma Platform and Ardmore Basin.

Source: "Environmental Aspects of Produced Waters from Oil and Gas Extraction Operations in Offshore Coastal Waters, prepared by OOC, Sept., 1976.

not be removed from the lignosulfonate complex even by strong ion-exchange resins and that the chromium is in the trivalent oxidation state (McAtee and Smith, 1969). Toxicity studies using *Mollienisias latipinna* (mollies) have indicated that the compound itself is of low toxicity (killed some test animal at 70 to 450 ppm concentrations). These concentrations could be found near discharge points (Hollingworth and Lockhart, 1975).

Heavy metals can also be introduced into sea water by the dissolution of drilling platform legs and pipelines. The metals released would be iron with lesser amounts of nickel and molybdenum. The time required for metal decomposition through chemical and microbial erosion is not presently known, but with present safeguards, may be around ten years. Dissolution would occur at a very slow rate and should not appreciably add to the concentration of heavy metals around platforms and pipelines in the water column or in sessile marine organisms, although this has yet to be demonstrated.

Concerning the levels of concentration of heavy metals in the marine environment, IDOE (1972) concluded that with the possible exception of lead, the current levels of heavy metals in marine ecosystems are derived primarily from natural rather than technological sources. However, local inputs in the estuarine and coastal environments can increase the levels in the water column, sediments and marine organisms. In a study of the effects of offshore petroleum operations on the environment, in the Gulf of Mexico, the Gulf Universities Research Consortium (GURC) concluded that all the heavy metals observed in the water column were in the ranges reported for oceanic waters except for barium for which the results were inconclusive. A zinc concentration gradient was found that decreased with distance from the oil platforms (GURC, 1974). However, the investigation did not analyze distribution of heavy metals in the marine organisms or in the sediments.

b. Uptake

Marine organisms can accumulate heavy metals by absorption across body surfaces and gills from the water or by ingestion of food containing heavy metals. Food sources can include heavy metals absorbed onto suspended particles or plankton, heavy metal compounds that have precipitated into the sediments and been ingested by deposit feeders, and heavy metals concentrated by organisms and preyed upon by other organisms in higher levels of the food web.

Once heavy metals are introduced into the ocean, concentrations are lowered by dilution and removed from sea water by precipitation, absorption, and absorption by marine organisms. The amount of dilution depends on the currents, mixing and circulation patterns in the area of discharges as well as the medium in which the metals are discharged. For example, heavy metals introduced in crude oil or formation water of greater density than the surrounding water would probably tend to mix less with the ambient water mass and retain their higher concentrations for a longer period of time. The use of diffuser technology in many sewage outfalls helps to dilute the effluents faster and prevents a large dose of highly concentrated effluent impacting one area at one time.

Precipitation of a metal to the sediments occurs if the concentration of the metal is higher than the solubility of the least soluble compound that can be formed between the metal and anions in the water such as carbonate, hydroxyl or chloride. The concentrations of heavy metals which can remain in solution are orders of magnitude higher than those usually found in the sea and normally the sea is considerably undersaturated with heavy metals (Bryan, 1971).

Adsorption of metals can occur on the surfaces of suspended and deposited particulate matter such as clays, phytoplankton, hydrated ferric oxide and hydrated manganese dioxide. However, all heavy metals are not equally readily absorbed. Zinc, copper and lead are probably readily adsorbed by both hydrated ferric oxide and hydrated manganese dioxide, but cobalt and nickel prefer hydrated manganese dioxide while silver is not readily adsorbed by either (Bryan, 1971). According to Lowman et al. (1971), surface adsorption, including ion exchange, is probably an important uptake path for phytoplankton. Glooschenko (1969) found that the greatest uptake of mercury-203 (^{203}Hg) per cell in a population of coastal marine diatoms (*Chaetoceros costatum*) was by adsorption onto a population killed with formalin rather than uptake by absorption of living cells. This passive uptake for the dead cells could also be due to increased membrane permeability to the mercury. In either case, the uptake

by adsorption was greater than the active adsorption process of live cells.

It has been found that heavy metals in natural waters are predominantly associated with particles suspended in water. Whenever attempts have been made in the natural environment to detect the amounts of heavy metals in solution versus the amount adsorbed onto or part of particles, investigators have discovered that only a small percentage of the heavy metals are in solution. It is not known if the particles that have adsorbed the heavy metals can be absorbed. It is generally thought that the particles must be ingested or taken into cells by phagocytosis and that the metal must be solubilized to be absorbed in solution (Hartung, 1972).

Uptake by absorption from sea water through the gills, body surface or gut wall is an important pathway for heavy metals to enter marine organisms. As noted by Anderson et al. (1974a), the accumulation of heavy metals by marine organisms from dilute sea water solutions has been well demonstrated. The amount of heavy metal absorbed depends on many physical and chemical factors such as the concentration of the heavy metal in solution, the chemical form of the complex, the ligands available for complexing the metals, particle size, the nature of the particles available for adsorption in the water, pH and alkalinity. Biological characteristics of the organism also affect the absorption rate and amount: the species of the organism, age, metabolic rate, and previous health (Hartung, 1972). A further complicating factor is that an equilibrium may be established between the organism, its food and the concentration of the heavy metal in the water (Lowman et al., 1971).

Concentration factors for various marine organisms for several elements including heavy metals are given in Table I-7. It can be seen that these factors range up to more than a million or more for the heavy metals. Concentration factor is defined as "the ratio of the concentration of an element or radionuclide in an organism or its tissues to that concentration directly available from the organism's environment under equilibrium or steady-state conditions" (Lowman et al., 1971). However, marine organisms accumulate heavy metals and other elements from many sources including food, water, suspended particles and deposited sediments. Therefore, the concentration factors listed should be viewed as indicators that can be changed by biological and environmental factors.

Absorption from solution through the gills of the lobster *Homarus vulgaris* results in a concentration of 7ppm of zinc in the lobster blood flowing through the gills, or 10^3 to 10^4 times the concentration in sea water. Before the zinc diffuses through the gill epithelium probably attached to proteins, zinc is first adsorbed onto the cuticle covering of the gills (Bryan, 1971). Anderson et al. (1974a) summarized recent studies of heavy metal uptake from sea water in marine animals as follows:

> Among the more recent studies, Eisler et al. (1972) have shown that mummichogs or common killifish, *Fundulus heteroclitus*, scallops, *Aquipecten irradians*, oysters, *Crassostrea virginica* and northern lobsters, *Homarus americanus*, exposed for 21 days to flowing sea water containing 10 ug/L (ppb) of cadmium accumulated the metal to levels equivalent to 45, 114, 352 and 41 percent, respectively, higher per unit wet weight than baseline levels of cadmium in the controls. Pentreath (1973) determined that exposure of the estuarine mussel, *Mytilus edulis* to zinc, manganese, iron and cobalt in sea water solution for 49 days resulted in maximum concentration factors of approximately 500, 250, 5000, 1000 respectively. Vernberg and O'Hara (1972) studied the effects of temperature-salinity stress on mercury uptake and accumulation in the gill and hepatopancreas tissues of the fiddler crab *Uca pugilator* and found significant uptake over 72 hours of exposure, with gill tissue accumulating greater amounts than hepatopancreas under all conditions.
>
> The NSF/IDOE (National Science Foundation/International Decade of Ocean Exploration) Pollutant Transfer Workshop reported on more recent findings of heavy metal uptake by marine organisms. The Skidaway group at the University of Georgia found that the marine plant *Spartina alterniflora* takes up mercury through its roots. Subsequently, the mercury is transferred to the leaves and then released to estuarine waters. The root system apparently concentrates inorganic mercury, while the leaves concentrate methylmercury (NSF/IDOE, 1974). Eelgrass (*Zostera marina*) in the coastal waters of Alaska absorb trace metals from the water and sediments and concentrate zinc, copper and cadmium in their roots, rhizomes and leaves. The eelgrass helps to recycle these trace elements in the food web that would normally be lost to the sediments (NSF/IDOE, 1974).

At the California Institute of Technology it has been discovered that the form of the heavy metal lead in sea water is critical to the knowledge of its behavior in the food chain. For example, the investigators found that much of the lead in sea water may be adsorbed on the mucilage of algae (NSF/IDOE, 1974). This is consistent with the findings of Flooschenko (1969) discussed earlier for the marine diatom *Chaetoceros costatum*. Chow et al. (1974) have also discovered that excessive amounts of lead collect on the epidermal mucous of fish. These observations are important since the biologically active fraction of lead in marine organisms might be small compared to the large

TABLE I-7 Ranges of Element Concentration Factors[a] in Marine Organisms at Various Trophic Levels[b]

Element	Algae: Sessile	Algae: Plankton (Phytoplankton and Sargassum)	Grazers: Plankton (Copepods, Pteropods, Salps, Doliolid)	Grazers: Shellfish	Predators: Plankton [Euphausiids, Planktonic Amphipods, Shrimp (Acanthephyra, Paleomonetes)]	Predators: Fish	Predators: Squid
Ag	(18) 100-1,000	(1) <100-220	(1) <100	(2) 330-2 x 10^4	(1) <45-900		(1) 900-3,000
Cd	(12,13) 11-20	(1) <350-6,000	(1) <80-10^5	(2) 10^5-2 x 10^6	(1) <300-10^4	(12) >10	(1) 2,800
Ce	(14) 100-3,300[c]	(4) 2,000-4,500[c]		(14) 40-300[c]		(14) 5-12[c]	
Co	(13,14,16) 15-740	(1,13,17) 75-1,000	(1) <110-10^4	(7) 24-260 (14) 18[c]	(1) <70-1,300	(14) 28-560	(1) <200-5 x 10^4
Cr	(14) 100-500	(1) <70-600	(1) <15-10^4	(2) 6 x 10^4-3 x 10^5	(1) <55-3,900	(8) 3-30	(1) <70
Cs	(14) 16-50	(14) 16-22	(3) 6-15[c]	(14) 3-15[c]		(14) 6-10	
Fe	(14) 10^3-5 x 10^3	(1) 750-7 x 10^4	(1) 440-6 x 10^4	(2) 7 x 10^4-3 x 10^5	(1) 3 x 10^3-3 x 10^4	(14) 400-3 x 10^3	(1) 10^3-3 x 10^3
I	(14) 160-7 x 10^3			(14) 40-70		(14) 10	
Mo	(9,16) 10-200	(1) <3-17	(1) 2-175	(2) 30-90	(1) <2-14	(9) ~200	(1) <10
Mn	(14) 20-2 x 10^4	(1,14) 300-7 x 10^3	(1) 21-4 x 10^3	(2,14) 3 x 10^3-6 x 10^4	(1) 270-1,600	(14) 95-10^5	(1) 10^3
Ni	(13,16) 50-10^3	(1) 25-300	(1) 2-10^3	(2) 4 x 10^3-10^4	(1) 17-90		(1) 30-80
Pb	(13) 8 x 10^3-2 x 10^4	(1,17) 10^3-3 x 10^6	(1) 3 x 10^3-2 x10^6	(2,6) 39-5 x 10^3	(1,15) 200-6 x 10^4	(10) 5-10^4	(1,15) 100-2 x 10^5
	(14)			(14)	(11)	(14)	

TABLE I-7 (continued)

Ru	$100-10^3$[c]			$1-16$[c]	10[c]	10[c]	
	(18) <200-1,200	(1) <200	(1) $<10-6 \times 10^3$		(1) <160-2,400		(1) <400-2,100
Sr	(14) 0.1-90	(1) 0.9-54	(1) 1-85	(5) ~50[c]	(1) 1.2-10	(14) 4-5	(1) 0.9-1.2
Ti	(18) $200-3 \times 10^4$	(1) $600-10^4$	(1) $28->3 \times 10^4$		(1) $110-2 \times 10^4$		(1) 300-3,000
Zn	(14,16) 80-3,000	(1) 200-1,300	(1) 125-500	(2,14) $1,400-10^5$	(17) ~50	(14) $280-2 \times 10^4$	(1) 2,500
Zr	(14) 200-3,000[c]	(1) $<1,000-2 \times 10^4$	(1) $360-3 \times 10^4$	(14) 8-36[c]	(1) $<800-4 \times 10^4$	(14) 5[c]	(1) 2×10^4

a Concentration in whole, fresh organism versus concentration in seawater.
b Literature references are shown in parentheses in upper left of box and listed below. No attempt has been made to achieve completeness; the ranges of concentration factors are for illustration, but are believed to be representative.
c Concentration from radionuclide tracer experiments.

(1) Bowen et al., unpublished; some data from Nicholls et al., 1959.
(2) Brooks and Rumsby, 1965.
(3) Bryan, 1963.
(4) Chapman, 1958.
(5) Cigna et al., 1963.
(6) Costa and Molina, 1957.
(7) Fukai, 1968.
(8) Fukai and Broquet, 1965.
(9) Fukai and Meinke, 1962.
(10) Goldberg, 1962.
(11) Hiyama and Khan, 1964.
(12) Hiyama and Shimizu, 1964.
(13) Ishibashi et al., 1964.
(14) Polikarpov, 1966.
(15) Tamotsu et al., 1964.
(16) Young and Langille, 1958.
(17) Vinogradova and Kovalskiy, 1962.
(18) Black and Mitchell, 1952.

From Lowman et al. (1971)

amounts of biologically inactive adsorbed lead on these organisms. This distinction has often been ignored in the past (NSF/IDOE, 1974).

The path of uptake can also depend on the element itself. Bryan (1964) found that zinc and copper were absorbed indirectly from the water into the lobster *Homarus vulgaris*, while Bryan and Ward (1965) discovered that manganese uptake was mostly from food for the same species of lobster. Pentreath (1973) investigated uptake of radioisotopes of zinc manganese, cobalt and iron by the mussel *Mytilus edulis* and reported that accumulation from sea water was minor compared to food accumulation. Pentreath indicated that uptake was from food particles as well as from mucous accumulation of metals in soluble form. Results of Hoss (1964) as reported by Bryan (1971) using zinc-65 in the flounder, *Paralychthys*, suggest that food is a more important source of zinc than sea water. Likewise, Preston and Jeffries (1969, as cited by Bryan, 1971) have shown that zinc and cobalt are absorbed from ingested particles through the gut rather than from sea water solution for the oyster *Ostrea edulis*.

In contrast, Polikarpov (1966) contends that chemical mineral substances are more generally accumulated directly from water than indirectly through the food chain. According to Lowman et al. (1971) the degree to which a trace element is taken up in a marine organism depends on the relative concentrations of the element in the water and food. When an element is concentrated in food only slightly above its concentration in water, the food supplies a relatively low fraction of the element for marine organisms. However, when the element is highly concentrated in food compared to sea water, a major fraction of the element may be accumulated from the food through the gut. The relative importance of uptake of heavy metals from water compared to uptake from food is still being studied and is by no means resolved for marine organisms. As mentioned above, it probably varies for different elements and organisms as well as for various relative concentrations.

Bryan (1973) reported a seasonal variation in the concentrations of trace metals in two scallop species from the English Channel. Variations between species were observed, but the highest values of metals occurred in the autumn and winter when phytoplankton productivity was low, while the values decreased when phytoplankton production increased. The metals looked at were Ag, Co, Cr, Cu, Mn, Ni, Pb, Zn, Al, Cd and Fe and they were concentrated in the kidneys and digestive glands to the greatest extent. Bryan reasoned that the seasonal variation was due to three factors:

1) More food from increased phytoplankton productivity in spring and summer results in increased metabolic activity for the scallop and increased excretion of wastes, including excess heavy metals.
2) The uptake of metals by phytoplankton decreases the concentration in the water. Also extracellular products from the phytoplankton may chelate metals in the water thereby reducing their availability to the scallops.
3) In the times of high productivity, the amount of metal/phytoplankton cell decreases, since the cell members increase and the metal concentrations remain virtually the same.

Other organisms besides particle feeders like the scallops probably have seasonal variations in their uptake of heavy metals, although there has been little investigation to date of this environmental variable.

Storage and Metabolism

Once heavy metals are taken up by marine organisms they are usually used in enzyme systems or stored in a particular body tissue, sometimes for just a temporary period. The place of storage in the organism and its subsequent pathway through the organism is dependent on several variables including the type of metal, the form of the metal complex, the method of uptake, species and the age of the organism. In general, elements that are concentrated in marine organisms can be grouped into one of the five categories: (1) structural elements—carbon, nitrogen and phosphorus (silicon, calcium and strontium, in some cases); (2) catalyst elements—iron, copper, zinc, manganese and cobalt (nickel, chromium, cadmium and silver may follow these elements); (3) elements easily hydrolyzed at sea water pH; (4) heavy halogens; and (5) heavy divalent ions—barium, radium and lead (Lowman et al., 1971). Most of the heavy metals of concern occur in the catalyst element group.

Different groups of marine organisms are able to accumulate and store heavy metals in their tissues depending on their ability to regulate the concentration in their body compared to the environmental concentration. This involves not only uptake and storage of heavy metals but also release of the metals back to the environment. For example, according to Bryan (1971) when the concentrations of metals such as zinc or copper in

sea water are increased, the concentrations in oysters increased appreciably while the concentrations in the flesh of crustaceans such as crabs or lobsters remain relatively constant. Storage sites for most organisms include the digestive glands, muscle tissue, skeletal tissue and gills.

For small marine crustaceans (*Euphausia pacifica*, *Thysanoessa spinifera*, *Pandulus stenolepis* and *P. platyceros*) Fowler et al. (1970) found that zinc-65 fed through a food chain accumulated primarily in the interstitial spaces between muscle fibers, in the eye, within the exoskeleton and on the interior surface of the exoskeleton. These locations were the same as those for storage of zinc-65 from water absorption processes. However, the source of the zinc affected the saturation levels of the tissues. When uptake was from food, the muscle tissue (and hepatopancreas at times) contained a higher percentage of the total zinc level in shrimps and euphausiids than the exoskeleton. When uptake was from water, the percentage of total zinc level was higher in the exoskeleton. The fact that a significant percentage of zinc was located in the exoskeleton from labelled food uptake suggests that the zinc was transported rapidly by the haemolymph from the gut to the exoskeleton (Fowler et al., 1970). The investigators concluded that since most of the zinc-65 was located between cells rather than inside of cells, most ingested zinc apparently accumulates in excess of the animals' needs and is not used metabolically.

In other marine crustaceans primary storage has been found to occur in the hepatopancreas for excess zinc in lobster blood and for excess copper in the shrimp *Crangon vulgaris* (Bryan, 1971). Another crustacean, the fiddler crab *Uca pugilator*, concentrated mercury primarily in the gill tissues with lesser amounts in the hepatopancreas and green gland. Very small amounts were found in the carapace and muscle tissues (Vernberg and Vernberg, 1972). See Figure I-5. The mode of uptake by the crab, however, was absorption of mercury from sea water.

Molluscs accumulate heavy metals in the digestive glands and kidneys primarily (Bryan, 1971; Bryan, 1973; Pentreath, 1973). Anderlini (1974) discovered high concentrations of cadmium (up to 1400 ppm) in the digestive glands of the red abalone *Haliotis rufescens* from samples along the California coast. He looked at eight heavy metals (silver, cadmium, chromium, copper, lead, mercury, nickel and zinc) and reported varying concentrations in the gills, mantle, digestive gland and foot muscle. The concentrations in the different tissues varied with the metal type, the concentrations of the metal in the sea water and the method of uptake. For example, nickel had the highest concentrations in the gill (up to 100 ppm), more than 2-3 times the nickel levels in other tissues. This was probably due to absorption and accumulation of nickel into the mucous sheets of the gills as well as absorption by the gills themselves (Anderlini, 1974). An investigation of several heavy metals in North Atlantic finfish revealed that muscle tissue of these Osteichthys species concentrated arsenic, cadmium, copper, mercury and zinc in varying amounts. Mercury and cadmium concentrations in muscle tissues of Chondrichthys species studied tend to be higher than those of Osteichthys while arsenic concentrations were definitely higher. The liver of Chondrichthys had higher concentrations of arsenic, cadmium, copper and zinc compared to other Chondrichthys tissues (Windom et al., 1973a). Silver, cadmium, chromium, copper, nickel, lead and zinc concentrate mainly in the gonads and liver of the Dover sole with smaller amounts in the epidermis. Specimens were taken from outfall and control areas off Southern California (SCCWRP, 1974). Chow et al. (1974) found lower concentrations of lead in tuna muscle than had been reported previously. Muscle tissue contained about 0.003 ppm of lead while epidermis had about 2 ppm in wet tissue. High concentrations in fish fins from tuna is due to the mucin secreted by the mucous cells of the epidermis which forms a mucous slime from a glycoprotein. The authors conclude that it is likely that strong heavy metal complexing sites in the proteins take up leak from sea water and incorporate it into the slime. They conclude that most of the lead in time is probably contained in this epidermal mucous layer and that it is unlikely that much lead passes through the skin barrier from sea water (Chow et al., 1974). Analysis of epidermal mucous and kidneys from an adult sculpin (*Scopaena guttata*) exposed to large concentrations of lead acetate over three months resulted in accumulation of lead in the mucous. The lead did not increase in the muscle tissue, but did increase in the kidney and bone. Apparently the kidney is metabolizing the accumulated lead and some of it is deposited in the bone (NSF/IDOE, 1974).

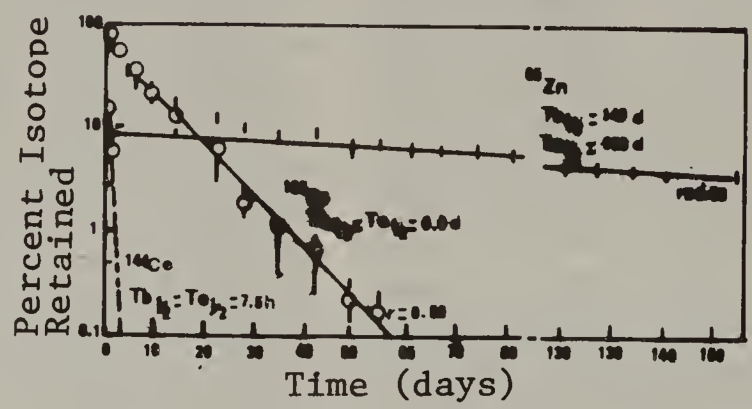


Figure I-5   <u>Euphausia pacifica</u>. Loss of three radionuclides from similar-sized euphasiids (Mean dry weight 2.4 mg). ^{65}Zn, n-3; ^{137}Cs, n-5; ^{144}Ce, n-2; r: correlation coefficient. Bars indicate ranges of animal activity. All data were corrected for physical decay of the isotope except ^{137}Cs. Tb½: biological half-life; Te½: effective half-life; 10°C. d: days. (From Fowler et al. 1971).

Evidence that the form of the metal compound is important for the storage site derives from observations of 70% of the total mercury in carnivorous fish muscle occurring as methylmercury. For invertebrate omnivores, the percentage of methylmercury is less. Samples of liver and spleen from sharks contained low amounts of methylmercury compared to total mercury (NSF/IDOE, 1974). At the cellular level, the distribution of lead-210 in sea cucumber embryos (*Strongylocentrotus purpuratus*) has been investigated by Nash (1975). He reported that embryos can absorb significant amounts of lead from levels as low as 4.81×10^{-6} ppm. Most of the absorbed lead was concentrated in the nuclear portion of the cell homogenate.

All of these investigations indicate that there are many variables involved in the storage and metabolism of heavy metals in marine organisms. At present little is still known about the pathways of uptake, metabolism, storage and release of heavy metals and their transport through the marine ecosystems.

c. Discharge and release into the marine environment

There have been few studies to date of the release or depuration of heavy metals from marine organisms to the marine environment. Although data on retention times are scanty, there are indications that metals concentrated in animal tissues are retained at significant concentrations for several months (Andersen et al., 1974b). Discharge of heavy metals from marine organisms can take place by ion exchange across cell membranes of gill and body surfaces, loss by molting exoskeletons that have concentrated heavy metals, excretion of heavy metals into the gut and loss by feces and excretions in the urine. All of these processes help an organism to regulate the concentration of heavy metals and other substances accumulated from sea water or food, but the extent and rate of their release is poorly known for heavy metals.

Bryan (1971) reports that excretion of metals across the gills appears to occur: in the shore crab, *Carcinus maenas*, and in the rainbow trout, *Salmo gairdnerii*. The cypiid larva of the barnacle, *Balanus amphitrite niveus*, excretes excess copper into the lumen of the gut and the octopus, *Octopus dofleini*, excretes both copper and zinc into the rectal fluid. Crustaceans can excrete copper, zinc, cobalt, manganese and mercury in the urine. Little information is known about excretion of heavy metals from fish except that excretion of zinc in the urine of the rainbow trout is relatively unimportant (Bryan, 1971). The rate of loss of methyl mercury from species of carnivorous fish is very slow. Methyl mercury in fish has a half-life of about two years according to Miettinen et al. (1971, as cited by Hartung, 1972).

A long-term experiment concerning the elimination of zinc-65, cesium-137 and cerium-144 by euphausiid shrimps determined that approximately 96% of the initial body concentration was eliminated over a five month period (Fowler et al., 1971). The biological half-life of ^{65}Zn was 140 days, and the percentage of ^{65}Zn lost in molts compared to the total in the organism was 1%. Assuming that loss through fecal pellets is small, the major mechanism for ^{65}Zn loss for euphausiids would be isotopic exchange with the water. From Figure I–5 it can be observed that approximately 90% of the ^{65}Zn was lost after 30 days.

In a study of the mussel, *Mytilus edulis*, and its accumulation of some heavy metal isotopes from sea water, Pentreath (1973) observed that the greatest accumulation was in the stomach and digestive gland for all isotopes. However, after two weeks iron-59 occurred in the mussel foot in the byssus gland area that attaches the mussel to the substrate. Following another two week period, the iron-59 clusters disappeared. The author postulated that the iron might be secreted into new byssus threads. After 42 days in filtered sea water, the loss of the metals from the stomach and digestive gland was as follows:

Percent loss in dry weight from stomach and digestive gland: Zinc, 23.1; Manganese, 14.3; and Iron, 52.2.

There was no loss from the adductor muscle (Pentreath, 1973). Yound and Folsom (1967, as cited by Pentreath, 1973) recorded a long half-life for zinc-65 in the mussel, *Mytilus californianus*, as 76 ± 3.5 days.

Other observations of release of heavy metals by molluscs include a biological half-life of 193 days for manganese excretion from scallops (Bryan, 1973). No appreciable decrease in the concentrations of cadmium and zinc in dog whelps and limpets was found in the Bristol Channel after seven weeks and three weeks cleansing in clean sea water. A crab (*Carcinus*

maenas L) lowered its zinc concentration significantly but not the cadmium concentration after seven weeks cleansing (Peden et al., 1973).

Therefore, from these few investigations one can find evidence that marine organisms can release heavy metals back to the environment, but the time of release is relatively long. There is some evidence to indicate that molluscs may not be able to regulate heavy metal concentrations in their tissues as well as crustaceans (Bryan, 1971). However, it is not known if this difference is due to separate pathways of uptake and storage, different methods of release or differences in the bonding of the metals and their complexes in the tissues.

d. Food web magnification

There is ample evidence to indicate that heavy metals accumulate in the marine food web in a variety of organisms at various trophic levels and through a variety of uptake pathways. As can be seen from the preceding discussion, heavy metals can be concentrated by absorption across gills, body surfaces and gut wells; adsorption into organisms, suspended and deposited particles; and taken up from food sources. The concentration factors listed in Table I-9 reflect tremendous abilities for marine organisms to concentrate elements from very dilute solutions in sea water. However, as mentioned previously the significance of the concentration factors is observed by the many variables and pathways involved in the uptake of heavy metals by marine organisms. Classical food web magnification, or the increasing concentrations of an element per weight of tissue in successively higher trophic levels, for heavy metals is complicated by not only the various uptake pathways but also by the ability of some organisms to release the heavy metals back to the marine environment eventually and therefore regulate concentrations in their tissues against environmental gradients. The whole process is just not well enough understood at this time.

Most of the characteristics of heavy metals in the marine environment favor their magnification in the food web. Like PCS's and synthetic chemicals, heavy metals are relatively resistant to chemical and biological degradation. Evidence has been presented that the half-life of metals in tissues is relatively long before being excreted. The half-life can range up to two years for methylmercury compounds in fish. The longevity of the metals in tissues and the high concentration factors of many marine organisms suggest that food web magnification can take place. Most of the incidents of high levels of heavy metals found in marine organisms in the ocean occur in coastal waters and point sources near pollution sources from land. A toxic effect on a consumer in the higher levels of the marine food web, including man, can result from feeding on organisms further down in the food web that have concentrated heavy metals at levels that have no apparent effect on the food organisms.

Besides the much publicized occurrence of mercury compounds in high concentrations in some tuna and swordfish, heavy metals such as arsenic, cadmium, copper, zinc, chromium, lead, nickel and silver have been reported in various organisms from the marine environment throughout the world (LeBlanc and Jackson, 1973; Stenner and Nickless, 1975; Peden et al., 1973; Stenner and Nickless, 1974; Anderlini, 1974; Windom et al., 1973a; Windom et al., 1973b; Chow et al., 1974; and Bryan, 1973). In a study of mercury in plankton in the North Atlantic, Windom et al. (1973b) reported concentrations of less than 0.2 to 0.4 ppm in open ocean plankton compared to 5.3 ppm in nearshore plankton in polluted areas. The samples included mostly copepods and arrow worms with eleven samples containing phytoplankton.

The authors hypothesized that the mercury was possibly transported from the nearshore plankton to the open ocean food web rather than through direct transport in the water since the dilution factors over the distances involved would be tremendous.

In a related study from the same area in the higher levels of the food web, Windom et al. (1973a) analyzed several heavy metals in various species of fin fish. In this investigation they found no tendency for onshore-offshore differences in concentrations for Osteichthys or Chondrichthys. There were differences in levels of accumulation and storage places for different metals in both groups as mentioned previously in this discussion. For Osteichthys arsenic concentrations ranged from less than 1.0 to 6.4 mg/g (ppm) and mercury concentrations from 0.1 to 3.0 mg/g. However, what is significant is that copper, cadmium and zinc concentrations were similar in all fish studied except for the smaller plankton-eating fish (anchovies and myctophids) which had much

larger concentrations of these metals than the other fishes. This would suggest depletion of these metals up the food chain, and not magnification, since the plankton on which these fish feed have an even higher concentration of these metals (Windom et al., 1973a).

A similar instance of food chain accumulation, but not magnification, could be found in predators of the red abalone, *Haliotis rufuscens*, off the California coast. Anderlini (1973) reported a high concentration of cadmium (up to 1400 ppm) in the digestive glands of the red abalone. However, cadmium levels in the kidneys of mollusc-eating sea otters (*Enhydra lutris*) off the California coast ranged from 89 to 300 ppm. Although this was higher than cadmium in fish-eating sea lions (from 18 to 63 ppm) from a comparable level in the food web, the point is that the cadmium levels did not approach those found in the abalone. Therefore, the cadmium was probably accumulated in the food chain, but classical magnification probably does not take place. Whether or not the levels of cadmium were increased in the next trophic level, the large amounts of cadmium in the higher level predators would be cause for concern. Other marine mammals, birds, fish and man at the upper levels of the marine food web can be affected by high concentrations of certain heavy metals accumulated in the food web.

What does this mean for heavy metals introduced into the ocean from offshore petroleum operations? Evidence has been presented that heavy metal concentrations in petroleum, formation waters and drilling fluids can range from 10 to 10^5 times the natural background levels of the open ocean (see Tables I-4-8). Therefore, events such as accidental massive or chronic oil spills, accidental loss of drilling fluids and the discharge of formation waters can introduce higher loads of heavy metals into the ocean. The introduced metals are then diluted by sea water, precipitated out, adsorbed on particles or other organisms and absorbed by some marine organisms to various degrees. These discharges would be localized sources occurring around drilling platforms for the most part.

Therefore, there could be some uptake of metals especially by the sessile organisms around the platforms. It is not known to what extent this occurs and to what levels the heavy metals would concentrate in the water column, sediments or marine organisms as a result of petroleum operations. The only investigation conducted so far concerning effects of heavy metals from offshore petroleum operations indicated that the concentration ranges of heavy metals in the water column was within the ranges for the metals in open ocean water except for barium where the data was inconclusive and a zinc gradient around the platforms probably due to the decomposition of the sacrificial covering of the platform legs (GURC, 1974).

The input of heavy metals to the marine environment and accumulation in the food web due to offshore petroleum operations should be far less significant than sources of heavy metals from land in most coastal waters such as river runoff, sewage effluent and industrial wastes. Since the effects of heavy metal input from offshore petroleum operations into the marine food web are largely unknown, it is advisable to continue to observe and monitor the marine environment for possible accumulation in the food web.

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Appendix J

Matrix Analysis of Potential Impacts on Major Resources and Activities

1. Purpose

The purpose of this matrix analysis is to analyze some of the potential impacts of the proposed OCS lease sale by way of a matrix analytical technique in an attempt to provide the decision-maker and reviewer with an array of factors which must be considered in order to form value judgements concerning the importance of these interactions.

In this section, each tract is included in a table designed to describe its distance from shore, water depth and expected type of production. In addition, the sensitivity of major resources and activities to impacts of oil spills, should one occur, and to impacts of offshore structures, should the tract be developed, is evaluated by means of a sensitivity rating for both spills and structures.

2. Significant Resource Factors

The matrix analysis examines major resource categories which could sustain negative impacts as a result of the development of the tracts included in the proposed lease sale. Significant resource factors appear on the horizontal axis of each matrix and for purposes of this analysis have been identified to consist of:

littoral systems
hard (live) bottom systems
other benthic systems
endangered species
commercial and sport fishing
shipping
aesthetics
outdoor recreation
cultural resources

All evaluations of the above categories were based on measurement from the edge of the tract closest to the resource potentially affected.

3. Impact Producing Factors

This evaluation considers the sensitivity of significant resources and activities to the occurrence of oil spills and offshore structures within the proposed sale area as being the primary factor. "Oil spills" in this context refers to spills of 100,000 gallons (2,381 bbls) or more (the volume designated as a major spill by the National Oil and Hazardous Substances Pollution Contingency Plan), and structures include platforms or other fixed structures and artificial islands.

Other impact-producing factors such as debris resulting from drilling activities and pipeline construction are non-specific and difficult to analyze on a tract-by-tract basis, and therefore, are not included in this matrix section. However, these and other related factors were discussed on the basis of this proposed sale in Sections III.B. and C.

4. Sensitivity Rating

Each tract has been assigned sensitivity values for oil spills and structures based primarily on the distance from a particular resource.

A series of scales has been devised for the purpose of assigning a range of values to indicate sensitivity to each impact-producing factor. These scales are presented below and consist of three levels of potential magnitude of impact:

3—Maximal potential impact
2—Moderate potential impact
1—Minimal potential impact

The judgement of the importance of any specific impact is at the discretion of the decision-maker or reviewer.

A. OFFSHORE STRUCTURES

An estimate of the impact of offshore structures on the environment consists of two factors: quantity—in this case, it is estimated that all tracts will average two structures per tract, even though some tracts may never be developed, and time—all structures will remain on site for an average period of fifteen to twenty years.

Structures are considered to be potentially negative impacts to four of the significant resource factors namely: hard (live) bottom systems, commercial and sport fishing, shipping and aesthetics.

Live bottom systems containing benthic epifauna and demersal fishes may be very sensitive to disturbances such as the turbidity created by the discharge of drill muds and cuttings. Also, demersal fish population distribution may be affected by the presence of a structure. Therefore, the sensitivity ratings for live bottom systems reflects these considerations and is purposely conservative due to our lack of information with regard to the distribution of drill muds and cuttings under operational conditions in marine systems and the distribution of this system type (live bottom) within the lease area. Therefore, we have assumed the presence of live bottom systems throughout the lease area.

Structures interfere with commercial fishing by removing trawling and purse seining areas. Approximately 70% of the catch by these two methods in the Southeast Georgia Embayment is

shoreward of the 20 m (66 ft.) isobath. The remainder of the catch by these methods is concentrated between the 20 m (66 ft.) and the 40 m (130 ft.) isobath with only nominal effort expended beyond these depths.

Structures pose a collision hazard to shipping and boating, in general, but are especially hazardous when placed near shipping lanes and are rated accordingly.

The aesthetic sensitivity ratings are based on the visibility from sea level of a 22 m (72 ft) tall structure. Within 16 km (10 mi) of shore, such a structure would be obvious, whereas 17 km (11 mi) to 25 km (15 mi) from shore the aesthetic impact would be greater than 25 km (15 mi) from shore the aesthetic impact would be negligible except from the point of view of the boating community.

Based on the above considerations, the sensitivity scale for structures was developed (Table J-1).

b. Oil spills

The same two factors for estimating the impact of oil spills on the environment are as follows: quantity—our analysis is based on spills of 100,000 gallons or more (2,381 bbls), and time—the toxicity of oil is known to decrease with weathering time which depends on the rate of travel of an oil slick. For analytical purposes, we have assumed a rate of 0.9 km/hr (0.5 kts) which for weathering times of 24, 48, and 72 hours gives impact zones of 19.3, 38.6, and 57.9 km (12, 24 and 36 naut. mi). Using toxicity at 24 hours as a base, laboratory bioassays indicate a decrease of toxicity by a factor of 0.90 for 48 hours weathering and 0.54 for 72 hours weathering (Hannah, 1976). Therefore, assigned sensitivity values of biological systems are adjusted for distance from a potential spill site by the appropriate weathering factor.

Oil spills are considered to be potentially damaging to all of the previously listed resource factors except shipping.

If a spill were to occur within the 16 km (10 mi) of any resource, it probably could not be effectively contained before contacting the resource. For this reason, the highest sensitivity rating was established for 16 km (10 mi) or less from littoral systems, endangered species, aesthetics, outdoor recreation and cultural resources. Within 17 km (11 mi) to 32 km (20 mi) the probability that oil would contact a resource is sufficient enough to warrant concern. Beyond 32 km (20 mi), the possibility of contact still exists but is considered to be minimal.

The sensitivity ratings for benthic systems and sport and commercial fishing are based upon water depths to which oil can be expected to be entrained into the water column. In nearshore areas 15 m (49 ft) or less in depth, a spill will almost certainly contact bottom sediments increasing the potential for damage to benthic systems and tainting of demersal species. Under extreme conditions of mixing energy, the depth to which oil might be entrained can be assumed to be 30 m (99 ft) or less. Sediments at water depths greater than 30 m (99 ft) have little chance of being contaminated with the exception of the immediate vicinity of the spill site.

Based on the above assumptions, the sensitivity scale for oil spills was developed (Table J-2).

To derive additional information from the matrix analysis tables (Table J-4) potential impacts upon individual resource and activity categories are totaled, on a tract-by-tract basis, resulting in a cumulative impact for each proposed lease tract. This is divided by the total possible cumulative value (12 for offshore structures, Table J-1 and 24 for oil spills, Table J-2) resulting in an impact index. These impact indexes are then summed resulting in an additive impact for each proposed lease tract. For example, tract number one has a cumulative impact for structures of 7.0 out of a possible total of 12 for an impact index of 0.58 for offshore structures. The same tract has a cumulative impact for 7.08 for oil spills out of a possible total of 24 for an impact index of 0.30. These are summed for an additive impact of 0.88 (0.58 + 0.30 = 0.88).

The evaluation of the impact index and additive impact ratings are listed in Table J-3. Utilization of the impact index and additive impact ratings found in the matrix analysis tables indicate that none of the proposed 225 lease tracts will have potential maximal impact on a tract-by-tract basis.

Abbreviations Used in the Matrix Analysis Tables

Tract designations in the matrix analysis tables are listed by tract number followed by the lease block locations. Lease block locations are shown on Visuals 1N and 1S. A description of each tract can be found in Appendix A.

JI - James Island, NI 17-12

Br - Brunswick, NH 17-2

Ja - Jacksonville, NH 17-5

OG - Oil and/or Gas Prone Tract

NA - Not Applicable

St/OS - Upper left portion of each analysis block pertains to the impact rating for Structures; lower right portion pertains to Oil Spills.

Table J-1. Sensitivity Scale for Structures

Hard (Live) Bottom Systems

3 - 1.5 km or less from known live bottom
2 - 1.5 to 5 km from known live bottom
1 - greater than 5 km from known live bottom

Sport and Commercial Fishing

3 - within 20 m depth contour
2 - within 40 m depth contour
1 - outside 40 m depth contour

Shipping

3 - within 1.5 km of shipping lane
2 - 1.5 to 5 km of shipping lane
1 - greater than 5 km from shipping lane

Aesthetics

3 - within 16 km of shore
2 - 17 to 25 km from shore
1 - greater than 25 km from shore

Table J-2. Sensitivity Scale for Oil Spills

Littoral System

3 - within 16 km of shore
2 - 17 to 32 km from shore
1 - greater than 32 km from shore

Hard (Live) Bottom System

3 - 15 m depth or less
2 - 16 to 30 m depth
1 - greater than 30 m depth

Other Benthic System

3 - 15 m depth or less
2 - 16 to 30 m depth
1 - greater than 30 m depth

Endangered Species

3 - within 16 km of known habitat
2 - 17 to 32 km from known habitat
1 - greater than 32 km from known habitat

Commercial and Sport Fishing

3 - 15 m depth or less
2 - 16 to 30 m depth
1 - greater than 30 m depth

Aesthetics

3 - within 16 km of shore
2 - 17 to 32 km from shore
1 - greater than 32 km from shore

Outdoor Recreation

3 - within 16 km of shore
2 - 17 to 32 km from shore
1 - greater than 32 km from shore

Cultural Resources

3 - within 16 km of shore
2 - 17 to 32 km from shore
1 - greater than 32 km from shore

Table J-3. Evaluation of Impact Index and Additive Impact Rating

Impact Index

1.00 - 0.78 maximal potential impact
0.77 - 0.56 moderate potential impact
0.55 - 0.33 minimal potential impact

Additive Impact

2.00 - 1.44 maximal potential impact
1.43 - 0.89 moderate potential impact
0.88 - 0.33 minimal potential impact

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location[1/]	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
1 JI 115	64	36	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
2 JI 153	63	29	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
3 J1 154	68	31	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
4 JI 159	92	36	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
5 J1 160	97	38	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
6 J1 197	48	31	OG	NA / .90	3 / 1	NA / 1	NA / .90	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.80	.58 / .33	.91

1/ Tract designations in the matrix analysis tables are listed by tract number followed by the lease block location. Appendix A presents a detailed description of each tract.

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
7 JI 198	52	33	OG	NA / .90	3 / 1	NA / 1	NA / .90	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.80	.58 / .33	.91
8 JI 199	55	35	OG	NA / .90	3 / 1	NA / 1	NA / .90	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.80	.58 / .33	.91
9 JI 203	68	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
10 JI 204	71	36	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
11 JI 241	49	31	OG	NA / .90	3 / 1	NA / 1	NA / .90	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.80	.58 / .33	.91
12 JI 242	55	33	OG	NA / .90	3 / 1	NA / 1	NA / .90	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.80	.58 / .33	.91

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
13 J1 243	58	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
14 J1 244	61	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
15 J1 245	64	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
16 JI 246	68	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
17 J1 247	71	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
18 J1 285	55	33	OG	NA / .90	3 / 1	NA / 1	NA / .90	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.80	.58 / .30	.88

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
19 J1 286	58	33	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
20 J1 287	61	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
21 J1 288	64	37	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
22 J1 289	68	38	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
23 JI 290	71	38	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
24 JI 291	74	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
25 JI 292	78	46	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
26 JI 329	58	31	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
27 JI 330	61	33	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
28 JI 331	64	38	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
29 JI 332	68	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
30 JI 333	71	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
31 JI 334	74	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
32 JI 335	77	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
33 JI 336	80	91	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
34 JI 373	61	38	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
35 JI 374	64	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
36 JI 375	68	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
37 JI 376	71	41	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
38 JI 377	74	43	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
39 JI 378	77	44	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
40 JI 379	80	46	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
41 JI 380	84	91	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
42 JI 417	63	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
43 JI 418	71	38	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
44 JI 419	74	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
45 JI 420	77	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
46 JI 421	80	46	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
47 JI 422	84	55	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
48 JI 423	87	91	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
49 JI 462	70	46	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
50 JI 463	76	45	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
51 JI 464	76	64	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
52 JI 843	69	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
53 JI 844	72	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
54 JI 886	69	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
55 JI 887	76	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
56 JI 888	78	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
57 Br 256	66	26	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
58 Br 299	60	27	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
59 Br 300	64	27	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
60 Br 301	69	29	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
61 Br 342	57	27	OG	NA / .90	3 / 2	NA / 2	NA / .90	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.80	.58 / .45	1.03
62 Br 343	66	27	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
63 Br 344	69	27	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
64 Br 345	72	33	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
65 Br 387	68	27	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
66 Br 388	69	29	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
67 Br 389	71	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
68 Br 608	84	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
69 Br 609	89	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
70 Br 610	92	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
71 8r 611	97	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
72 Br 651	85	39	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
73 Br 652	89	41	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
74 Br 653	92	43	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
75 Br 695	93	39	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
76 Br 696	97	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
77 Br 739	84	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
78 Br 740	95	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
79 Br 781	85	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
80 Br 782	89	36	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
81 Br 783	92	38	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
82 Br 784	95	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
83 Br 825	85	33	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
84 Br 826	89	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
85 Br 827	92	36	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
86 Br 868	77	29	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
87 Br 869	81	31	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
88 Br 870	86	33	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
89 Br 871	91	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
90 Br 872	96	37	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
91 Br 873	103	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
92 Br 874	106	44	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
93 Br 911	74	27	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	.92
94 Br 912	78	15	OG	NA / .54	3 / 3	NA / 3	NA / .54	3 / 3	1 / NA	1 / 1	NA / 1	NA / 1	8 / 13.08	.67 / .55	1.22
95 Br 913	84	16	OG	NA / .54	3 / 2	NA / 2	NA / .54	3 / 2	1 / NA	1 / 1	NA / 1	NA / 1	8 / 10.08	.67 / .42	1.09
96 Br 914	89	18	OG	NA / .54	3 / 2	NA / 2	NA / .54	3 / 2	1 / NA	1 / 1	NA / 1	NA / 1	8 / 10.08	.67 / .42	1.09

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
97 Br 915	92	37	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
98 Br 916	98	22	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
99 Br 917	103	24	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
100 Br 918	108	26	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
101 Br 920	115	46	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
102 Br 953	65	27	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
103 Br 954	70	31	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
104 Br 955	74	15	OG	NA / .54	3 / 3	NA / 3	NA / .54	3 / 3	1 / NA	1 / 1	NA / 1	NA / 1	8 / 13.08	.67 / .55	1.22
105 Br 956	78	16	OG	NA / .54	3 / 2	NA / 2	NA / .54	3 / 2	1 / NA	1 / 1	NA / 1	NA / 1	8 / 10.08	.67 / .42	1.09
106 Br 957	84	17	OG	NA / .54	3 / 2	NA / 2	NA / .54	3 / 2	1 / NA	1 / 1	NA / 1	NA / 1	8 / 10.08	.67 / .42	1.09
107 Br 958	89	19	OG	NA / .54	3 / 2	NA / 2	NA / .54	3 / 2	1 / NA	1 / 1	NA / 1	NA / 1	8 / 10.08	.67 / .42	1.09
108 Br 959	93	21	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
109 Br 960	98	24	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
110 Br 961	103	24	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
111 Br 962	105	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
112 Br 963	110	44	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
113 Br 964	115	46	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
114 Br 993	53	26	OG	NA / .90	3 / 2	NA / 2	NA / .90	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.80	.58 / .45	1.03
115 Br 994	58	26	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
116 Br 997	65	27	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
117 Br 998	70	29	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
118 Br 999	75	31	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
119 Br 1000	80	16	OG	NA / .54	3 / 2	NA / 2	NA / .54	3 / 2	1 / NA	1 / 1	NA / 1	NA / 1	8 / 10.08	.67 / .42	1.09
120 Br 1001	85	18	OG	NA / .54	3 / 2	NA / 2	NA / .54	3 / 2	1 / NA	1 / 1	NA / 1	NA / 1	8 / 10.08	.67 / .42	1.09

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
121 Br 1002	74	20	OG	NA / .54	3 / 2	NA / 2	NA / .54	3 / 2	1 / NA	1 / 1	NA / 1	NA / 1	8 / 10.08	.67 / .42	1.09
122 Br 1003	95	22	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
123 8r 1004	98	23	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
124 Br 1005	103	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
125 Br 1006	108	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
126 Br 1007	113	44	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
127 Ja 25	55	25	OG	NA / .90	3 / 2	NA / 2	NA / .90	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.80	.58 / .45	1.03
128 Ja 26	60	27	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
129 Ja 27	64	29	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
130 Ja 28	69	29	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
131 Ja 29	74	13	OG	NA / .54	3 / 3	NA / 3	NA / .54	3 / 3	1 / NA	1 / 1	NA / 1	NA / 1	8 / 13.08	.67 / .55	1.22
132 Ja 30	78	15	OG	NA / .54	3 / 3	NA / 3	NA / .54	3 / 3	1 / NA	1 / 1	NA / 1	NA / 1	8 / 13.08	.67 / .55	1.22

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
133 Ja 33	92	39	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
134 Ja 34	97	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
135 Ja 35	102	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
136 Ja 36	107	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
137 Ja 37	112	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
138 Ja 38	117	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
139 Ja 68	51	24	OG	NA / .90	3 / 2	NA / 2	NA / .90	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.80	.58 / .45	1.03
140 Ja 69	55	25	OG	NA / .9C	3 / 2	NA / 2	NA / .90	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.80	.58 / .45	1.03
141 Ja 70	60	29	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
142 Ja 71	62	31	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
143 Ja 72	67	31	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
144 Ja 73	74	15	OG	NA / .54	3 / 3	NA / 3	NA / .54	3 / 3	1 / NA	1 / 1	NA / 1	NA / 1	8 / 13.08	.67 / .55	1.22

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
145 Ja 74	78	17	OG	NA / .54	3 / 2	NA / 2	NA / .54	3 / 2	1 / NA	1 / 1	NA / 1	NA / 1	8 / 10.08	.67 / .42	1.09
146 Ja 76	87	39	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
147 Ja 77	92	39	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
148 Ja 78	97	39	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
149 Ja 81	110	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
150 Ja 114	58	29	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
151 Ja 115	63	31	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
152 Ja 116	68	33	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
153 Ja 117	73	33	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
154 Ja 118	78	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
155 Ja 120	88	37	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
156 Ja 121	95	39	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
157 Ja 122	98	39	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
158 Ja 123	102	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
159 Ja 158	58	26	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
160 Ja 159	64	29	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
161 Ja 160	68	31	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
162 Ja 164	88	36	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
163 Ja 165	93	20	OG	NA / .54	3 / 2	NA / 2	NA / .54	3 / 2	1 / NA	1 / 1	NA / 1	NA / 1	8 / 10.08	.67 / .42	1.09
164 Ja 166	97	20	OG	NA / .54	3 / 2	NA / 2	NA / .54	3 / 2	1 / NA	1 / 1	NA / 1	NA / 1	8 / 10.08	.67 / .42	1.09
165 Ja 167	102	22	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
166 Ja 168	107	40	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
167 Ja 202	60	26	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
168 Ja 203	65	27	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
169 Ja 207	84	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
170 Ja 208	88	37	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
171 Ja 209	95	20	OG	NA / .54	3 / 2	NA / 2	NA / .54	3 / 2	1 / NA	1 / 1	NA / 1	NA / 1	8 / 10.08	.67 / .42	1.09
172 Ja 210	100	22	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
173 Ja 211	105	23	OG	NA / .54	3 / 2	NA / 2	NA / .54	2 / 2	1 / NA	1 / 1	NA / 1	NA / 1	7 / 10.08	.58 / .42	1.00
174 Ja 250	82	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
175 Ja 251	86	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
176 Ja 252	95	36	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
177 Ja 253	98	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
178 Ja 293	77	33	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
179 Ja 294	82	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
180 Ja 295	87	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
181 Ja 296	92	37	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
182 Ja 339	86	37	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
183 Ja 345	115	44	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
184 Ja 382	81	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
185 Ja 383	86	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
186 Ja 384	91	37	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
187 Ja 389	115	46	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
188 Ja 390	120	64	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
189 Ja 426	81	33	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
190 Ja 427	86	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
191 Ja 428	91	37	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.58 / .30	.88
192 Ja 431	104	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
193 Ja 432	109	44	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
194 Ja 433	114	55	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
195 Ja 434	119	91	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
196 Ja 470	80	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
197 Ja 471	85	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
198 Ja 472	90	37	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
199 Ja 475	103	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
200 Ja 476	108	44	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
201 Ja 477	113	55	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
202 Ja 478	118	101	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
203 Ja 519	105	44	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
204 Ja 520	110	46	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
205 Ja 521	115	64	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
206 Ja 557	75	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
207 Ja 558	80	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
208 Ja 559	85	37	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
209 Ja 562	98	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
210 Ja 563	105	44	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
211 Ja 564	108	53	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
212 Ja 565	114	91	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
213 Ja 601	74	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
214 Ja 602	79	35	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
215 Ja 606	98	40	OG	NA / .54	3 / 1	NA / 1	NA / .54	2 / 1	1 / NA	1 / 1	NA / 1	NA / 1	7 / 7.08	.58 / .30	.88
216 Ja 607	101	46	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
217 Ja 608	108	55	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
218 Ja 609	111	91	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
219 Ja 650	98	42	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
220 Ja 651	101	46	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
221 Ja 652	108	55	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
222 Ja 653	110	165	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80

TRACT DATA				RESOURCE AND ACTIVITIES									IMPACT		
Tract Number Lease Block Location	Distance from Shore (kilometers)	Approximate Depth (meters)	Estimated Type of Production	Littoral Systems	Hard (Live) Bottom Systems	Other Benthic Systems	Endangered Species	Sport and Commercial Fishing	Shipping	Aesthetics	Outdoor Recreation	Cultural Resources	Cumulative Impact	Impact Index	Additive Impact
223 Ja 696	104	82	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
224 Ja 740	103	91	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
225 Ja 784	102	110	OG	NA / .54	3 / 1	NA / 1	NA / .54	1 / 1	1 / NA	1 / 1	NA / 1	NA / 1	6 / 7.08	.50 / .30	.80
			OG	NA /	/	NA /	NA /	/	/ NA	/	NA /	NA /	/	/	
			OG	NA /	/	NA /	NA /	/	/ NA	/	NA /	NA /	/	/	
			OG	NA /	/	NA /	NA /	/	/ NA	/	NA /	NA /	/	/	

Appendix K

Economic Study of the Possible Impacts of a Proposed Oil and Gas Lease Sale off the U.S. South Atlantic Coast

INTRODUCTION

The task of measuring economic impacts of an event that occurs in the future might be seen by some to be an almost hopeless task. Not only does one need to have a clear idea of the extent of the action that is causing the impact but one needs a clear idea of the future in order to measure the impacts. In the case of the exploration and development of oil and gas resources on the Outer Continental Shelf (OCS) in a frontier area the problems are greatly compounded. First, the degree of uncertainty of any resource estimates in a frontier area is great. Second, the geographic dispersion of the potential resources is such that the onshore impact area that must be considered is large. The potential for impacts includes four states and twenty-nine coastal counties. The number of potential locations for pipeline landfalls, onshore terminals and onshore bases is large and when one starts considering the number of possible combinations the problem can quickly become unmanageable. Further, the large size of the area and the diversity of the economic activities adds complexity to any predictions that can be made about the future. Third, besides being affected by the level of resources, the location of resources, the physical availability of good onshore sites, direct impacts will be dependent upon the decision that will be made both by industry developers and local governments. New coastal zone management legislation, zoning restrictions, a tax incentive offered by one community, or a strong local opposition will ultimately be as important in locational decisions as any of the other factors.

Two approaches exist in trying to assess impacts. The first approach is descriptive, where the economist describes the general movements and trends that economic logic predicts. An example of this approach would be the statement that population will be expected to increase in an area with new industries. The second approach is a quantitative approach that attempts to measure relative magnitudes of changes as well as directions. Current environmental assessments put great emphasis on the importance of these measurements. To try to derive a quantitative measure of impacts an economist must model the situation. An economic model is nothing more than an attempt to abstract from a complex reality certain predictive structural relationships. It can be as simple as a statement that for every new job created, one new family will move into town consisting of a husband, a wife, two children and one dog; or as complex as the dynamic multicomponent models that must be run in stages because of the lack of a computer large enough to run the entire program.

The level of complexity in the problem attached to OCS hydrocarbon development suggests that a fairly complex model will have to be developed. Fortunately a predictive model of economic behavior on a county basis exists that lends itself quite well to OCS impact analysis. The Harris Model was developed by Dr. Curtis B. Harris, Jr. of the University of Maryland (Harris, 1972, 1973). Dr. Thomas Grigalunas of the University of Rhode Island, and the Bureau of Land Management, New York OCS Office, have used the Harris Model to measure impacts of the development of the Georges Bank (Grigalunas 1975, BLM in press). The New York OCS Office also used the Harris Model to measure impacts of development in the Baltimore Canyon Trough (BLM 1974). A related application was a study made to trace the economic effects of locating strip mining coal production in Montana (Fisher and Krutilla 1975).

Several reasons exist for our decision to use the Harris Model in the South Atlantic. The primary reason is the use of the Harris Model in the Mid and South Atlantic areas. In effect our work has been lessened by the effort that has gone before us in adapting the model and ironing out specific problems involved in the OCS application. Further, the use of the same model in different areas facilitates comparative analysis between the areas. All projections that come out of the Harris Model are consistent with a set of national and regional totals. Although local models might give a better quality of locally specific data, no other models that we were aware of covered the entire coastal region necessary for the Sale 43 analysis. The interstate consistency provided by the Harris Model is an important element of the impact analysis.

> BLM's use of the Harris economic model to project the extended economic and demographic effects of Mid-Atlantic OCS development represents an important effort to improve on conventional impact estimation methodologies by use of a new analytic technique. The Harris Model goes beyond conventional input/output models of industrial economic ac-

tivity by attempting to explain the location of economic activities and impacts on a very detailed sub-regional scale. Indeed, the model predicts, on a county-specific basis, the level of such variables as production, employment and earnings by industry, consumer expenditures, unemployment, investment, government expenditures, personal income and intercounty migration. Such an array of output data is impressive, and is indicative of a commendable effort (*Resource Planning Associates 1976*).

This study is divided into three chapters. Chapter I describes the Harris Model. In particular it deals with the logic of the model, some of the more important structural relationships, some of the more important assumptions and the data sources. An assessment of some of the advantages and disadvantages of the model is also included. Chapter II discusses the specific application of the model to the proposed Sale 43 impact analysis. The logic behind the development of alternative scenarios along with all of the scenario-specific assumptions is included.

A final word of caution should be given here. Economic modeling is an abstraction from reality. In the South Atlantic we did not feel confident enough about any one view of the future to use it exclusively for our impact analysis. Instead, three alternative futures without development were compared with eleven development scenarios. This gives us a range of hypothetical impacts. The final result of development will not mirror any of the proposed scenarios. Hopefully it will vindicate our analysis and fall somewhere within our estimated range but we cannot even promise this with certainty. Analysis of this nature might be able to serve as a planning guide but only with considerably more work on area specific analysis and only after the approximate location of reserves were known. Further, this analysis only measures economic variables and as such is not a measure of social welfare. Other social goals must be given a weight in planning that is commensurate with their importance. Economic analysis of the type presented here can never be more than a step of a more comprehensive analysis.

CHAPTER I

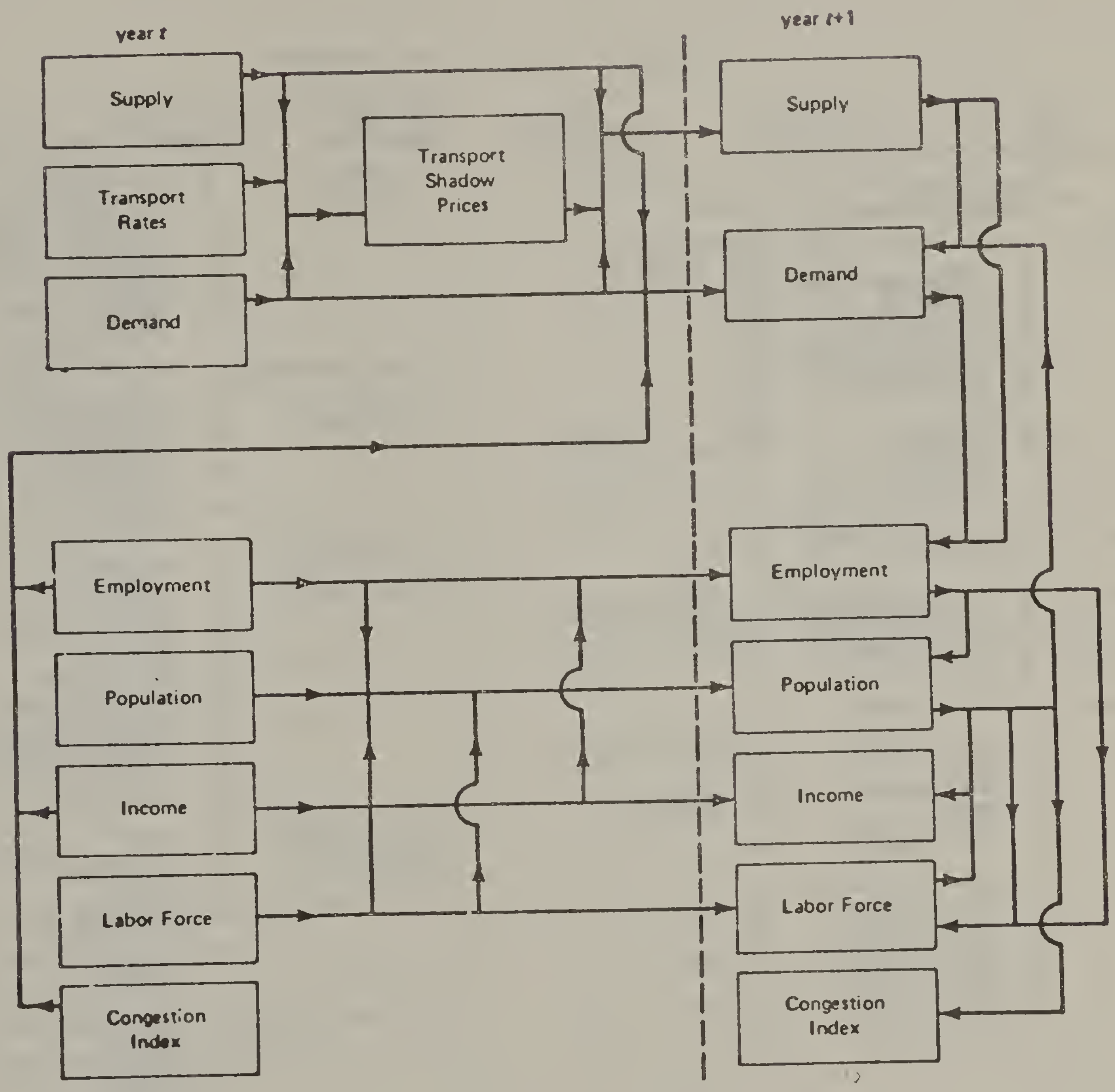
The Harris Model

What up to now has been referred to as the Harris Model describes a multiregional, multi-industrial forecasting model that has been developed by Dr. Curtis B. Harris, Jr. of the University of Maryland. This chapter hopes to present a concise explanation of some of the major components of the model. A more complete explanation can be found in *Locational Analysis* (Harris, 1972), and *The Urban Economics, 1985* (Harris, 1973), and *The Urban Economics, 1985: A Numerical Supplement* (Harris, 1976). The reader is urged to consult these sources for a more detailed overview.

The driving mechanism of the Harris Model is the postulate that a firm will try to maximize profits when making decisions on where to locate. An individual firm in an unfavorable location might not move in the short run because of the sunken costs of immobile capital equipment. However, in the long run, capital will be allowed to depreciate and new investments will occur in favorable locations causing shifts in the geographic distribution of an industry. The location of each industry is therefore a function of geographically different prices, restrictions, and markets (demand and supply) that face the industry for both inputs and outputs and "agglomeration variables" which Harris uses as a measure of locational externalities that are not fully captured in the different prices. Employment follows the industrial shifts and in turn is used to predict population, earnings and personal income. The final demand sectors, consumption, governmental expenditures, investment, and foreign exports are then calculated. The model is recursive in that it uses the values calculated for the first year, t+1, as input variables to forecast the values in the second year t+2, which in turn are used to forecast the values in t+3, etc., for as long as the model is run. A simplified flow diagram of the model is included as Figure 1. A more detailed discussion of the various components of the model follows.

The Harris Model divides industrial output into 99 industrial sectors. The 99 sectors represent an aggregation of the thousands of different industrial plants in the United States. The 99 sectors used by Harris correspond closely to the Office of Business Economics (OBE) input-output sectors of the U.S. economy. In order to facilitate our analysis, these sectors were further aggregated in the output produced for the South Atlantic model runs into 20 sectors, all model calculations were performed at the intermediate 99 sector level of aggregation. Table 1 shows the various levels of

Figure I - Simplified Flow Chart of Multiregional, Multi-industry Forecasting Model.



Source: Harris, 1973.

Table 1

Sectors Used in Forecasting Model

South Atlantic Output Sectors	Harris Model Industrial Sectors	SIC Numbers
A. Agricultural & Food Processing	1. Livestock	Part 01, Part 02
	2. Crops	Part 01, Part 02
	4. Agricultural Services	071, 072, 073, 074
	14. Meat Packing	201
	15. Dairy Products	202
	16. Canned & Frozen Foods	203
	17. Grain Mill Products	204
	18. Bakery Products	205
	19. Sugar	206
	20. Candy	207
	21. Beverages	208
	22. Miscellaneous Food Products	209
	23. Tobacco	21
B. Forestry and Fisheries	3. Forestry and Fishery Products	08, 09
C. Non Petroleum Mining	5. Iron Ore Mining	101, 106
	6. Non Ferrous Ore Mining	102,103,104,105,108,109
	7. Coal Mining	11, 12
	9. Mineral Mining	141,142,144,145,148,149
	10. Chemical Mining	147
D. Petroleum Mining	8. Petroleum Mining	13
E. Apparel and Textiles	24. Fabrics and Yarn	221,222,223,224,226,228
	25. Rugs, Tire Cord, Misc. Textiles	227, 229
	26. Apparel	225,23,3992,-239
	27. Household Textiles and Upholstery	239
F. Lumber and Wood Products	28. Lumber and Production Excl. Containers	24, -244
	29. Wooden Containers	244
	30. Household Furniture	251
	31. Office Furniture	25, - 251
	32. Paper and Production Excl. Containers	26, -265
	33. Paper Containers	265

Table 1 (continued)

South Atlantic Output Sectors	Harris Model Industrial Sectors	SIC Numbers
G. Chemical and Plastics	35. Basic Chemicals	281,286,287,289
	36. Plastics and Synthetics	282
	37. Drugs, Cleaning, and Toilet Items	283, 284
	38. Paint and Allied Products	285
	40. Rubber and Plastic Products	30
H. Petroleum Refining	39. Petroleum Refining	29
I. Leather, Glass and Stone	41. Leather Tanning	311, 312
	42. Shoes and Other Leather Products	31, -311, -312
	43. Glass and Glass Products	321, 322, 323
	44. Stone and Clay Products	324,325,326,327,328,329
J. Iron and Steel	45. Iron and Steel	331, 332, 339
K. Other Metals	46. Copper	3331, 3351, 3362
	47. Aluminum	3334, 3352, 3361
	48. Other Non Ferrous Metals	3332,3333,3339,334, 3356,3357,3369
	49. Metal Containers	341, 3491
	50. Heating, Plumbing, Structural Metal	343, 344
	51. Stamping Screw Machine Products	345, 346
	52. Hardware, Plating, Wire Products	342,347,348,349,-3491
L. Machinery and Miscellaneous Manufacturing	13. Ordnance	19
	53. Engines and Turbines	351
	54. Farm Machinery and Equipment	352
	55. Construction and Mining Machines	3351, 3352, 3533
	56. Material Handling Equipment	3534, 3535, 3536
	57. Metal Working Machinery and Equipment	354
	58. Special Industrial Machinery	355
	59. General Industrial Machinery	356
	60. Machine Shops and Misc. Machinery	359

Teble 1 (continued)

South Atlentic Output Sectors	Harris Model Industrial Sectors	SIC Numbers
L. Machinery and Miscelleneous Manufacturing	61. Office and Computing Machines	357
	62. Service Industry Machines	358
	63. Electric Apparatus and Motors	361, 362
	64. Household Appliences	363
	65. Electric Light and Wiring Equipment	364
	66. Communicstion Equipment	365, 366
	67. Electronic Components	367
	68. Batteries and Engine Elec. Equipment	369
	69. Motor Vehicles	371
	70. Aircraft end Parts	372
	71. Ships, Treins, Treilers, Cycles	373, 374, 375, 379
	72. Instruments end Clocks	381, 382, 384, 387
	73. Opticel end Photographic Equipment	383, 385, 386
	74. Misc. Manufectured Products	39, -3992
M. Transportetion	75. Trensportation	40,41,42,44,45,46,47
N. Communications	34. Printing & Publishing	27
	76. Communication	481, 482,489
	77. Radio, Television, Broadcesting	483
O. Utility	78. Electric Utility	491, 4931
	79. Ges Utility	492, 4932
	80. Weter Utility	494, 495, 496, 497
P. Wholesale Trade	81. Wholesale Trade	50
Q. Finance, Insurance end R. E.	82. Finance end Insurance	60,61,62,63,64,66,67
	83. Reel Estate end Rental	65, -654
R. Amusement and Service	84. Motels, Personal end Repair Service	70,72,76,-7694,-7699
S. Reteil Stores	85. Business Services	654,63,7694,7699,81,39, -736,-892
	89. Lumber, Housewares, Farm Equip. Stores	52

Table 1 (continued)

South Atlentic Output Sectors	Harris Model Industriel Sectors	SIC Numbers
S. Retail Stores	90. General Merchendise Stores	53,-532
	91. Food Stores	54
	94. Apparel, Accessory Stores	56
	95. Furniture Stores	57
	96. Eating, Drinking Places	58
	97. Drug end Proprietary Stores	591
	98. Other Reteil Stores	59, -591
	99. Nonstore Retailers	532
T. Medical and Educational Inst.	88. Medicel end Educetionel Institutions	736,80,82,84,86,892
U. Auto Dealers and Service	86. Automobile Repair Services	75
	92. Automotive Dealers	55, -554
	93. Gesoline Service Stations	554
V. Construction	11. New Construction	Part 15, Part 16, Pert 17
	12. Maintenance Construction	Part 15, Part 16, Pert 17

aggregation with the corresponding Standard Industrial Classification numbers.

An equation to explain the locational decision was developed for 84 out of the 99 industrial sectors in the locational analysis with the remaining sectors (all construction, transportation, and trade sectors) location being considered dependent upon the 84 sectors. It postulates that the change in the locational concentration of an industry sector, measured by the change in the output of that sector, is a function of the different marginal costs that it faces and the agglomeration variables. The generalized equation is shown as Figure II. The equation simply states that the change in the value of output of an industry in a region is a function of the marginal costs and the agglomeration variables faced by the industry in the region.

One of the most important elements of the marginal costs faced by an industry is the costs of transportation of both the inputs into the production process and the outputs that must be transported to the demand locations. A major component of the Harris Model is the linear programming transportation algorithms performed on the primary sectors to determine the transporation shadow prices (which can be shown to be equivalent to the marginal transportation costs under optimal conditions). Two sets of shadow prices are estimated through this procedure: 1) the cost of shipping a marginal dollar's worth of goods produced by industry i from region j, and 2) the cost of receiving a marginal dollar's worth of goods produced by industry i to region k. The variables that have been calculated originally entered as independent variables in the location equations. In the current version of the model the transportation variables are converted into a location rent (discussed below). The transportation costs that enter into the model are computed for each county, by weight class, using the lowest rate available of either the rail or highway freight rates.

Besides the costs of transportation, other costs that differ geographically include the costs of capital, land values, and regional wage rates. Land values and regional wage rates are self-explanatory and vary over time in response to demand and supply conditions. However, capital costs may vary in many ways. Geographic variations in the costs of borrowing money were found to be small and were not used in estimating equations. Although it was recognized that the marginal costs of constructing new capital might vary significantly no variable could be found to measure this effect. Another way that capital costs influence locations is through the existence of capital stock. To incorporate this influence two explanatory variables enter the equations, the capital equipment purchased by the industry and the prior level of output.

Some of the agglomeration variables used to try to capture the locational economies and diseconomies include population density, the output of major supplying industries and measures of major buyers. An example of how this measures externalities might be that an area with a high concentration of a type of industry would be expected to have a well developed labor market and support infrastructure.

Figure III shows the actual equations that have been used in various formations of the model to determine the change in output. The equations are fairly self-explanatory. All small i's refer to the sector classifications shown in Table I. Small j's refer to regional area that the equation is being run on. The dependent variable is the change in output excluding output resulting from defense expenditures, which is treated as exogenously determined. All of the independent variables can be classified as marginal costs (or proxy input prices when no measure of marginal costs was available) or agglomeration variables. The original structure of the equations is shown by equation 1. Equation 2 represents the improved version.

Both equations have the same theoretical formation. In equation 1 the marginal costs associated with the transporation algorithm are shown as input costs (TI) or the output prices (TQ). Only 4 major transportation costs variables are allowed to enter into the equation. Input prices include the wage rate, defined as a wage-output ratio (WR) and the value of land (VL). Proxies for the influence of capital costs are the level of output (Q) and the prior equipment purchases (EQ). Agglomeration variables include a measure of the major buyers (MB), the major suppliers (MS), and the population density (DEN).

Equation 2 was designed from equation 1 to reduce the multicollinearity problems that caused many of the hypothesized variables in the original equations to be excluded from the forecasting equations (the statistical technique used is described below). The possible 18 variables of equation 1 have been combined into six variables in equation 2.

Figure II: A Generalized Equation to Forecast Regional Change in an Industry's Value of Output.

$$\Delta Q_{kj} = f(MC_{1j}, \ldots, MC_{mj}; AG_{1j}, \ldots, AG_{gj})$$
$$(j = 1, \ldots, NR; k = 1, \ldots, NI)$$

where ΔQ_{kj} = change in value of output of industry k in region j,

MC_{ij} = marginal cost of obtaining the ith input in region j.,

AG_{ij} = a variable measuring the agglomeration effects i in region j,

m = number of inputs,

g = number of agglomeration variables,

NR = number of regions,

NI = number of industries.

Source: Harris, 1972.

Figure III. Equations to Forecast Regional Change in an Industry's Value of Output

(1) $\Delta QD_{ij}^{t} = f_{i1}(TQ_{ij}^{t-1}, TI_{s_k j}^{t-1}, WR_{j}^{t-1}, Q_{ij}^{t-1}, VL_{j}^{t-1}, EQ_{hj}^{t-1}, DEN_{j}^{t-1}, MB_{ijk}^{t-1}, MS_{ijk}^{t-1})$ (i = 1, ..., NI) (j = 1, ..., NR) (k → 4) (s_k max q_{si}) (h → 1)s

(2) $\Delta QD_{ij}^{t} = f_{i2}(S_{ij}^{t-1}, LR_{ij}^{t-1}, D_{ij}^{t-1}, IS_{ij}^{t-1}, VL_{j}^{t-1}, EQ_{hj}^{t-1})$ (i = 1, ..., NI) (j = 1, ..., NR) (h → i)

where

D_{ij}^{t} = Total demand for goods classified by industry i located in region j in year t.

DEN_{j}^{t} = Population density (per square mile) in region j in year t.

EQ_{j}^{t} = Equipment purchases by equipment purchasing sector i located in region j in year t.

IS_{ij}^{t} = Input scarcity of goods required by industry i in region j in year t.

LR_{ij}^{t} = Locational rent associated with industry i located in region j in year t.

MB_{ikj}^{t} = Major buying sector k located in region j that bought goods from industry i in year t.

MS_{ikj}^{t} = Major supplying sector k located in region j that sold goods to industry i in year t.

NI = Number of industries.

NR = Number of regions.

Q_{ij}^{t} = Output of industry i located in region j in year t.

QD_{ij}^{t} = Output less defense expenditures of industry i located in region j in year t.

S_{ij}^{t} = Total supply of goods classified by industry i located in region j in year t.

TI_{ij}^{t} = Transport cost of obtaining a marginal unit of input from industry i into region j in year t.

TQ_{ij}^{t} = Transport cost of shipping a marginal unit of output from industry i out of region j in year t.

VL_{j}^{t} = Value of land per acre in region j in year t.

WR_{ij}^{t} = Annual earnings per worker in labor sector i working in region j in year t.

q_{ik}^{t} = Input-output technical coefficient (national sales from industry i to industry k per unit of output for industry k) in year t.

f_{ik} = Denotes the functional relationship in sector i in equation k.

Source: Harris, 1976.

The location rent variable (LR) replaces up to 6 variables; (1) the variable for shipping products to market (TQ); (2) the 4 (maximum) transportation variables for obtaining inputs (TI); and (3) the wage rate (WR). The output price variable (TQ) is turned into a locational rent variable by changing its sign. The input cost variable TI are turned into locational rent values by calculating the difference paid by the county and the county in the worst location. National input-output coefficients are then used to weigh the "rents" which are then combined to obtain the total locational rent. All of the input prices are allowed to enter into the equation. The locational rent of the wage-output ratios is the difference between the wage-output ratio of a county and the maximum wage-output ratio in the industry. The three locational rents are summed together to obtain (LR).

The demand variable (D) replaces the variables that represented major buyers (MB). Originally up to 4 major buyers were separately identified. Now all major demanders are identified and combined into one variable referred to as total demand (D).

Input scarcity (IS) replaces the up to 4 variables identified as major suppliers (MS). It is an estimate of the total value of inputs that have to be imported into a county that are used for the production of other commodities.

The supply variable (S) which includes domestic production and foreign imports, replaces the output variable (Q). The value of land (VL) and equipment purchases (EQ) are the same in both equations. The density variable (DEN) was dropped because of its high correlation with the value of land (VL).

Because of the importance of equation 2 and the driving equation of the model something needs to be said about the estimating techniques. A step-wise linear regression technique was used where the variables were entered in steps by their rank of theoretical importance. Before a variable was accepted as part of the equation it must have met three tests: 1) the standard (t) test of statistical significance, 2) the sign of the variable must have the postulated theoretical sign and 3) the variable must not have severe multicollinearity with other variables already in the equation. In this way a tight control was kept over the theoretical aspects of the model. This resulted in a locational equation which emphasized sound economic theory rather than a high multiple regression coefficient. The order of entry of variables into the equation is the order established in equation 2.

All regional variables are entered as a share of a national total. This mechanism constrains the sum of all regional forecasts to be no more than the national forecast. The national forecasts are from an input-output model of the U.S. economy developed by Dr. Clopper Almon (Almon, 1974). The Almon model is a flexible input-output model that predicts changing technical coefficients and a changing product mix (due to changes in prices and final demand) over time. The updating of the Almon model is an ongoing process. Output from the Almon model is used not only to constrain the output equations but to constrain most of the Harris model's other forecasts that will be discussed below.

Data on the value of output was entered for all counties where a sector was located for the years 1965-1966. Where data was not available it was estimated with care taken to keep state or regional totals at the known levels. This resulted in a potential of 3,112 observations but in all cases the actual number of observations were less than this maximum. All of the locational equations along with information on the number of observations and threshold levels can be found in one of Dr. Harris' books (Harris 1972, Harris 1973, and Harris 1974).

In using the output equations to forecast regional output one other modification was made. If a region is in a favorable position for an industrial sector, but no previous output exists in that region, the model will try to locate output in that region. It will be allowed to do so only if the output level reaches a predetermined threshold level. The threshold is determined by the median reporting plant size provided that this plant size is below the average plant size. All threshold levels are given in terms of the value of output.

A thorough explanation of the remaining equations is not included as part of this study. A brief description of some of the more important structural relationships follows:

1. Federal government expenditures are generally treated as exogenous and held at a constant level.
2. State and local government and "general" federal government (mainly the post office) expenditures are considered a function of the prior level of personal income and grow as personal income grows.
3. Investment is determined by the forecast level of total output. Investment includes equipment purchases and industrial construction.
4. Employment is forecast by relating to the appropriate levels of output and equipment purchases. Employment by industry is the number of jobs located at the place of work. The number of persons employed by place of residence is ob-

tained by adjusting the number of jobs by the number of multi-job holders and the number of commuters in an area.

5. Population is forecast by equations that explain population migration, births, and deaths. Population migration in the working age groups is a function of economic factors including changes in the level of employment, the regional labor surplus or deficit and the average regional wage rates. Migration of youths is a function of the migration of the working groups while migration of retirement groups is a function of the prior level of population in these areas.
6. Total labor force is estimated by relating it to population in working age groups and the population associated with the labor surplus or deficit.
7. Personal income is defined as the sum of earnings, transfer payments and property income minus the social insurance payments made by employees. Earnings are forecast for all 99 industry sectors with regional shares of employment and equipment and equipment purchases used as explanatory variables. Transfer payments were forecast as a function of population and unemployment. Property income is estimated by relating it to earnings by place of residence.

Most of the variables that are forecast have a constraint on the amount that they can grow in a time period. The constraint is based on the average deviation of a variable's regional shares and is applied to the regional share. If, for example, one of the forecast variables was constrained at 10% and zero growth was forecast at the national level, the maximum regional growth rate would be 10%. If, however, the national growth rate was positive, the regional growth rate could be more than 10%, and conversely if the national rate was negative the regional rate would have to be less than 10%. Examples of the constraint levels are:

1. Output cannot increase more than 10% or decrease more than 5%.
2. Productivity cannot increase more than 10% or decrease more than 2%.
3. Wage rates cannot increase more than 5% or decrease more than 2%.
4. Unemployment cannot increase more than 10% or decrease more than 5%.

The constraints are not hit very often and are usually only hit in small counties with undeveloped infrastructures. For the South Atlantic we have required that the computer be programmed to indicate every time a constraint is hit.

Dr. Harris has indicated three principal limitations of the model: 1) the disequilibrium nature of the model, 2) the derivation of transportation variables from linear programming, and 3) the data used in the application of the model (Harris, 1972). These will be discussed along with other critiques that the Harris model has received.

Because the model is a disequilibrium model it is not a good predictive model for industries that are close to equilibrium. Although it is not likely that any given industry is in equilibrium, some are obviously closer than others to equilibrium. This implies the model is more applicable to some industries than to other industries.

The shadow prices computed for the transportation linear programming algorithm are only equal to the marginal transportation costs under optimum conditions. If an optional trade flow existed no cross-hauls should be observed. A cross-haul is simply the output from any one sector moving from region A to region B, and from region B to region A. The fact that they are observed can be attributed to several factors. One factor is the level of aggregation that goes into the modeling. For example both industrial chemicals and fertilizers are included as basic chemicals but their output is not interchangeable. Hence we might observe trade going between two regions when each region had the sector, basic chemicals. The other reason for observing cross-hauls is the definition of the geographic unit. Trade may be flowing from region A to region B in the northern part of the region and from region B to A in the southern part of the region. By doing the analysis on an area as small as a county this kind of cross-haul is minimized.

By far the weakest area of the model is the data base. Over one thousand data items are entered for each county. In the present version of the model, output estimates are based on two years observations, 1965 and 1966, and data on employment and population is based on 1970. Since the model's output observations were restricted to two years it was necessary to use output where changes in output would have more theoretical desirability. If more than two years' data was available an appropriate system of lags could be determined. Because of disclosure problems, data during these two years were not available for all counties. When data was not available it had to be estimated from other variables. Although careful controls were maintained with known totals this still introduces a potential source of error. Once again, the smaller underdeveloped counties will be the ones most prone to errors of this type. Under an existing contract with the Bureau of Land Management, data on employment for 1971 and 1972 and earnings and output for 1970 and 1971 are being calculated and will be included in the model shortly to improve the data estimates.

One of the most eloquent critiques of the Harris Model appears in *Identification and Analysis of Mid-Atlantic Onshore OCS Impacts* by Resource Planning Associates, Inc. An evaluation of their four major concerns follows:

1. One of the concerns expressed is the often weak statistical significance of some of the output equations used in the model. The statistical significant weakness of some of the equations can be caused by any one of the factors that are discussed above, and as Resource Planning Associates point out "underscores the complexity of explaining economic behavior on such a finely detailed level". Two additional points, however, need to be considered. The first point is that a low multiple regression coefficient does not necessarily lead to a bad forecast. The low multiple regression coefficient means that a large residual term remains. The residuals are incorporated into the regional forecasts which means that the model has a strong bias to leave the regional distribution of these industries constant. Since many of these industries have strong natural resource ties (i.e., mining sectors), a factor not accounted for in the model, or large capital requirements within, this bias is probably correct. In the case of industries with large capital requirements, the threshold levels also tend to restrict geographic mobility. The second point is that the statistical significance of the model's derived geographic distribution of total output is very high in all cases. This helps confirm its validity for use in geographic economical analysis.

2. Resource Planning Associates are concerned about the constraints placed on the percent growth in output that can occur in any given sector in a region. They feel that "such a constraint limits the ability of this model to explain economic change in any area where a new industry is entering and experiencing considerable economic growth". We share their concerns but after discussions with Dr. Harris we are not convinced that the constraints are utilized to an extent that would impair the model's usefulness. An industry has an incentive to locate where input supplies and output demands are located. Given the kinds of locations available in the South Atlantic, growth will most likely occur around already developed areas. Nevertheless we have requested that the model indicate every time a constraint is used. If this appears to be a problem in the analysis different assumptions will be used.

3. The third concern has to do with problems of using national coefficients in regional analysis. National coefficients do not take into consideration changes in the input mix caused by local input prices if they vary from national prices. This concern has also been raised by others who point out the better regional specification of industry inputs incorporated into many regional studies. The ideal situation would be a model that incorporated many finely detailed regional models into a national whole. The Harris model is capable of including regional coefficients if a consistent set of regional coefficients was available. In the South Atlantic we were faced with a tradeoff between several regional models, none of which covered our entire sale area, and the Harris model. The reasons for picking the Harris model are discussed in the introduction. We recognize that the use of national coefficients is a limitation of the Harris model, but we still feel that the Harris model results are generally valid despite this limitation.

4. The last concern deals with the interpretation of the model's results to quote: Finally, it is perhaps too easy to treat the model's predictions of the location of economic and demographic impacts as though those impacts had been determined by a completely internal, consistent set of locational relationships. In fact, the locational impacts are not primarily due to the model; rather, they are primarily determined by the initial assumed allocation of direct OCS activities and facilities to specific counties within the region. In this respect, and as mentioned by BLM, the model predictions represent a limited scenario built on specific assumptions regarding the location, timing, and magnitude of primary OCS development impacts.

We concur that the primary element that determines the model's results is the scenario assumptions that are used as inputs.

We have broadened the scope of the analysis to consider more than one set of assumptions. The development of these assumptions will be the subject of the next chapter. However, it should be emphasized that our assumptions are just that, and any interpretation of the results of the model should be made with full knowledge of all of the limitations of the model and the assumptions going into it.

CHAPTER II

O.C.S. Scenario Development

A total of seven model runs have been made on the proposed South Atlantic Sale 43. These represent five specific OCS development scenarios and two base cases. To explain the logic that goes into the building of the scenarios, this chapter has been broken into four separate sections that follow the logical sequence of scenario development.

The first two sections deal with the initial assumptions that were developed before the sale-specific scenarios. These involve assumptions on economic variables that are used in forecasting the future; and assumptions on the levels of resources that might be producible if the proposed sale is held.

Given the above sets of assumptions, five scenarios were developed. The scenario developments described in the third section were made after consultations with industry and government figures on likely paths that they see for the future development in the South Atlantic states. The development of the scenarios represented a multi-disciplinary effort to arrive at the level of detail necessary for the computer analysis.

Table II represents an integral part of this section. It details all of the important assumptions by year and county for all scenarios and base cases. It is hoped that the material presented in this fashion will help the reader to distinguish between the inputs to the various scenarios.

The remaining section shows the format of the output sections and explains some of the data classifications. This is to give the reader some idea of the types of data forecast by the Harris Model to help in the interpretation of the model's results.

Economic Assumptions

Economic variables that were specified can be divided between those that were used to define structural relationships in the U.S. economy and those that describe the future economic climate of the South Atlantic coastal region. Assumptions concerning the unemployment rate, price of oil and gas, material and labor availability, type of leasing system, and oil and gas imports all are assumptions that describe the future U.S. economy. These assumptions stay the same for all base cases and scenarios. The only assumption on the future South Atlantic economy that we entered was the specification of the amount of refining capacity. This enters the model as two cases—with and without refining and will be discussed later.

Table II shows a comparison of the different scenarios. Assumptions on the U.S. economy are not included as part of this table because they stay constant throughout. A discussion of the economic assumptions follow:

1) It is assumed that the civilian unemployment rate will be 9% in 1975, 6% in 1976, and 4% in subsequent years.

In formulating this assumption, it was decided that a steady rate of unemployment would expedite the analysis. A higher unemployment rate, or an unemployment rate that followed a cyclical pattern might have been a more realistic assumption. Our application of the model, however, is primarily concerned with using the Harris Model to show the effects of incremental changes in the economy produced by the proposed South Atlantic Sale 43 and we were interested in changes caused by (or impact of) development rather than the absolute level of development. If cyclical swings had been incorporated the impact analysis would have been complicated by the effort to sort out the effects of cyclical swings from the effects of OCS development. The unemployment rate goes into the model as a national unemployment rate. Regions can vary from this rate depending on forecast regional conditions.

2) The well-head prices of oil and natural gas are: oil—$11.00 per barrel, and natural gas—$1.50 per thousand cubic feet.

The price of oil and gas we are estimating is a long-term real price for the period beginning three to five years from the date of the lease sale, and extending 15 to 20 years into the future.

On July 27, 1976, the Federal Power Commission announced officially a new uniform national base rate for interstate gas of $1.42 per MCF with a four cent escalator per annum. This rate is applicable for (1) sales of natural gas made from wells commenced on or after January 1, 1975, and (2) sales made pursuant to contracts executed on or after January 1, 1975, for the sale of natural gas in interstate commerce. Since natural gas produced from the OCS is classified as interstate gas, the FPC's ruling directly affects our price assumption for natural gas for use in the economic impact analysis model. The price of gas was determined based on the fact that when appropriate BTU adjustments are added to the new

Table II - Comparison of Base Cases and Scenarios

	Year	Base I	Base II	A	B	C	D	E
OCS Resource Estimates								
Oil (Billion Barrels)		no development		.282	.282	.282	1.009	1.009
Gas (Trillion Cubic Feet)		"	"	0	1.890	1.890	6.810	6.810
Average daily production Oil:	1982	no development		3000	same rate as A		8000	Same rate as D
	1983	"	"	7000	"	"	25000	" "
	1984	"	"	11000	"	"	41000	" "
	1985	"	"	16000	"	"	55000	" "
	1986	"	"	23000	"	"	77000	" "
	1987	"	"	30000	"	"	99000	" "
	1988	"	"	37000	"	"	134000	" "
	1989	"	"	45000	"	"	162000	" "
	1990	"	"	56000	"	"	170000	" "
	1991	"	"	56000	"	"	170000	" "
	1992	"	"	56000	"	"	170000	" "
	1993	"	"	56000	"	"	170000	" "
	1994	"	"	56000	"	"	170000	" "
	1995	"	"	56000	"	"	170000	" "
	1996	"	"	56000	"	"	170000	" "
Gas:	1986	no development of gas		"	200	same rate as B	701	same rate as D
	1987	"	"	"	274	" "	726	" "
	1988	"	"	"	342	" "	726	" "
	1989	"	"	"	421	" "	1359	" "
	1990	"	"	"	466	" "	1397	" "
	1991	"	"	"	466	" "	1397	" "
	1992	"	"	"	466	" "	1397	" "
	1993	"	"	"	466	" "	1397	" "
	1994	"	"	"	466	" "	1397	" "
	1995	"	"	"	466	" "	1397	" "
	1996	"	"	"	466	" "	1397	" "
Operations Base Location	1977	no development		Chatham,Ga.	Chatham,Ga.	Chatham,Ga.	Glynn,Ga.	Glynn,Ga.
	1978						Charleston	Charleston,S.C.
	1979						Duval,Fla.	Duval, Fla.

Comments

1) Any oil and gas production that is shown is sold. Oil and gas production continues until 2006. Only the 20 years that are modeled are shown.

2) OCS oil production replaces imports in the rest of the nation in A; B; and C; and in D and E production replaces imports to a hypothetical refinery in the South Atlantic

3) No gas is produced and sold in A.

4) Special assumption B and C: oil is located in the southern tract area and gas is located in the northern tract area.

Operations Base Location:

1) All operations bases are based on an estimate from the Offshore Operators Committee on the size base necessary to provide supply and support for 56,000 b/d of stable production
   a) Cost = $1,027,000
   b) Employment = 103 persons

2) Area operation base locations are assumed to serve as place of employment for all offshore personnel.

Exploration # Drilling vessels/ # wells drilled	Year	Base I	Base II	A	B	C	D	E
	1977	no development		4/12	same rate as A		4/12	same as D
	1978	"	"	5/15	"	"	10/30	"
	1979	"	"	5/15	"	"	10/30	"
	1980	"	"	3/9	"	"	10/30	"
	1981	"	"	3/9	"	"	7/21	"
	1982	"	"	2/5	"	"	5/15	"
	1983	"	"	2/5	"	"	5/15	"
	1984	"	"	2/5	"	"	5/15	"
	1985	"	"	2/5	"	"	5/15	"
	1986	"	"	1/3	"	"	3/9	"
	1987	"	"	1/3	"	"	3/9	"
	1988	"	"	1/3	"	"	3/9	"
	1989	"	"	1/3	"	"	1/3	"
	1990	"	"	1/3	"	"	1/3	"
	1991	"	"				1/2	"
	1992	"	"				1/2	

1) Assumptions used for all scenarios
   a) Cost - $2,000,000/well
   b) Drilling rate - 3 wells/year/drilling vessel
   c) Employment - 113/drilling vessel

2) The decision not to produce gas in A was assumed to have no impact on exploratory drilling expenditures

3) All investment and employment is assigned in scenarios A, B, C to Chatham Co., Ga., and in scenarios D, E it is evenly divided between the three operations bases except during years of declining exploration where the one drilling vessel operates out of Glynn County, Ga.

Development #Platforms: Location of invest. timing	Year	Base I	Base II	A	B	C	D & E: Duval	D & E: Glynn	D & E: Charleston
				Chatham County, Georgia			For both D & E		
	1980	no development		1	1	same as B	0	1	1
	1981	"	"	1	2	"	1	0	1
	1982	"	"	2	2	"	0	2	1
	1983	"	"	2	2	"	2	0	1
	1984	"	"	1	1	"	0	2	1
	1985	"	"	1	1	"	0	3	0
	1986	"	"		1		3	0	0
	1987	"	"				1	1	1
	1988	"	"				0	1	2

1) Assumptions common to all scenarios:
   a) no more than 2 drilling rigs on each platform, no more than 20 wells per platform
   b) each rig can drill 5 wells per year
   c) development wells cost $500,000/well
   d) drilling rigs employ 65 persons/rig
   e) scenarios A,B,C, after initial drilling is complete one rig remains active doing service wells and workovers, in scenarios D, E this is increased to 2 rigs
   f) platforms cost $25,000,000/platform
   g) permanent platform employ 22 persons

2) Scenario A eliminates all GS predicted gas wells and two platforms

Table II - continued

Comparison Factors	Year	Base I	Base II	A Chatham County, Georgia	B	C	D For both D and E Duval	Glynn	E Charleston	Comments
#Wells: Location of invest. timing	1981	no development		5	5	same as B	0	5	5	
	1982	"	"	13	15	"	6	7	12	
	1983	"	"	22	25	"	7	21	22	
	1984	"	"	34	40	"	6	27	27	
	1985	"	"	26	30	"	11	40	24	
	1986	"	"	17	20	"	0	50	10	
	1987	"	"	17	20	"	20	40	0	
	1988	"	"	4	5	"	20	20	20	
	1989	"	"	4	5	"	0	23	17	
	1990	"	"	4	5	"	0	12	13	
	1991	"	"	4	5	"	0	11	9	
	1992	"	"	4	5	"	0	3	2	
	1993	"	"	4	5	"	1	2	2	
	1994	"	"	4	5	"	1	2	2	
	1995	"	"	4	5	"	0	4	1	
	1996	"	"	4	5	"	2	2	1	

Table II - continued

Comparison Factors	Base I	Base II	A	B	C All oil to refinery in Chatham	D	E All oil to refinery in Chatham	Comments
Transportation of OCS products Oil	none	none	All oil tankered; offshore storage treatment facility constructed 1982-1985; all oil tankered outside the area	Initial tankering of oil, pipeline built to Duval Co.,Fa. (65 miles) in 1985; oil then is tankered outside the region	Initial tankering of oil, in 1985 a pipeline built to nearest shore point-Glynn (40 miles marine) then overland to refinery; pipeline mileage by county: Glynn - 16 Brynn - 12 Chatham - 24 McIntosh - 46 Liberty - 8	Initial tankering of oil; 1985 90 miles of pipeline built to Duval Co, Fa.; 1988, 65 miles of pipeline built to Charleston Co.,S.C., all oil is then tankered from these ports to the rest of nation	Initial tankering of oil; 1985, 175 miles of marine pipeline and 5 miles land pipeline built to a refinery in Chatham Co., Ga.	1) Investment per mile of major pipeline was estimated at: $1,000,000/mile marine; $300,000/mile on land. All investment costs were allocated to the county that contained the land fall in the case of marine, or the county that it occurred in for overland pipelines 2) All land distances include an additional 20% assumed to be necessary for finding a suitable right-of-way.
Gas	none	none	none	68 miles of marine natural gas pipeline built to Charleston in 1986	68 miles of marine natural gas pipeline built to Charleston in 1986	82 miles of marine natural gas pipeline built to Duval Co., Fa. in 1986. 70 miles of marine natural gas pipeline built to Charleston S.C. in 1989	75 miles of marine natural gas pipeline built to Glynn Co.,Ga. in 1986. 70 miles of marine natural gas pipeline built to Charleston,S.C. in 1989	3) All gas pipeline is assumed to have an additional 5 miles of land pipeline for tie in to existing distribution systems. 4) Oil pipelines that go onshore to the refinery in Chatham has an extra 5 miles of overland pipeland to connect with refinery.

Table II - continued

Comparison Factors	Base I	Base II	A	B	C	D	E	Comments
Terminals and Processing Facilities								
Gas Processing	none	none	none	500 mmcf/day processing plant built in Charleston S.C., in 1985	500 mmdf/day processing plant built in Charleston S.C., in 1985	700 mmcf/day processing plant built in Charleston S.C., in 1988; and Duval Co., Fla., 1985	700 mmcf/day processing plant built in Glynn Co., Ga. 1985; and in Charleston Co., S.C. in 1988	1) Cost of 500 mmcf/day gas processing plant $40,000,000; employment 25 persons. 2) Cost of 700 mmcf/day gas processing plant costs $60,000,000 and employs 30 persons
Oil Terminals	none	none	Offshore oil terminal	Terminal and tankering port in Duval CO., Fla., 1985	Terminal and pumping station, Glynn Co., Ga. 1985	Terminal and tankering port Duval Co., Fla.,1985 Charleston, S.C., 1989	Terminal-pumping facility in Chatham, Co. Ga., 1985	1) Terminal facilities, by scenario: A. Offshore Terminal Investment schedule; 1982-$2,100,000; 1983 - $15,200,000; 1984-$50,900,000; 1985-$5,600,000 Employment - 36 B. Terminal connected with port facility costs-$4,000,000 Employment - 13 C. Terminal and pumping station $3,000,000 Employment - 9 D. Terminals connected with port $4,000,000 Employment - 13 E. Terminal and pumping station $4,000,000 Employment - 17

Table II - continued

Comparison Factors	Year	Base I	Base II	A	B	C	D	E	Comments
Petroleum Refining Constrained level of output - Chatham Co., Ga. (million dollars)	1976	188	188	same as	Base I	same as	same as	same as	1) Petroleum refining sector constrained to level proportional with growth in total output (minus petroleum sector) in Base I
	1977	197	197	"	"	Base II	Base I	Base II	
	1978	206	206	"	"	"	"	"	
	1979	215	215	"	"	"	"	"	
	1980	224	224	"	"	"	"	"	
	1981	232	232	"	"	"	"	"	2) Base II is constrained in the same manner until the completion of a fully integrated refinery in 1982
	1982	241	no constraints	"	"	"	"	"	
	1983	249	" "	"	"	"	"	"	
	1984	258	" "	"	"	"	"	"	
	1985	268	" "	"	"	"	"	"	3) Petroleum refinery completed Chatham Co., Ga., 1982, specifications: Capacity - 200,000 barrels/day Costs - $500 million Employment - 550
	1986	278	" "	"	"	"	"	"	
	1987	287	" "	"	"	"	"	"	
	1988	297	" "	"	"	"	"	"	
	1989	307	" "	"	"	"	"	"	
	1990	316	" "	"	"	"	"	"	
	1991	325	" "	"	"	"	"	"	
	1992	334	" "	"	"	"	"	"	
	1993	350	" "	"	"	"	"	"	
	1994	366	" "	"	"	"	"	"	
	1995	383	" "	"	"	"	"	"	
	1996	399	" "	"	"	"	"	"	
Miscellaneous									
Central Office Employment Starts - 1977 and continues throughout		no development		30	30	30	42	42	1) A central office employment is located in Chatham Co., Ga. No new office is required.
Pollution Containment Equipment investment:							same for D and E		
1) Location Costs	1977	no development		Chatham,Ga. $300,000	Chatham,Ga. $300,000	Chatham,Ga. $300,000	Glynn,Ga. $300,000		1) Pollution containment and cleanup equipment is located at operations base.
2) Location Costs	1978						Charleston,S.C. $300,000		2) The refinery at Chatham is assumed to have its own pollution equipment.
3) Location Costs	1981			Chatham,Ga. $470,000	Chatham,Ga. $470,000	Chatham,Ga. $470,000	Glynn, Charleston $470,000 $470,000		
4) Location Costs	1982						Duval,Fa. $470,000		

base rate of $1.42, which is based heavily on the cost of production reports submitted by producers, the national average wellhead price for regulated interstate gas will be about $1.50 per MCF. Therefore, $1.50 in constant price is reasonable for use in the economic impact analyses. The price for oil was arrived at after consideration of several factors. Based on the second stage of implementation of the Energy Policy and Conservation Act, the FEA estimated that domestically produced new oil price will be $13.95 (in current price) at the end of the 40-month control period. However, there is a good possibility for the price control to be extended repeatedly and influence price levels well beyond the 40-month period of control. Therefore, an upward price movement could be adjusted by a ceiling price imposed by regulation. Consequently, about $11 per barrel of domestically produced new oil looks quite reasonable as a long-term real price.

3) No material or labor constraints are assumed to exist in the South Atlantic.

A full discussion of this assumption is contained in Section III of the Draft Environmental Statement, OCS Sale 43.

4) No new refinery is expected as a direct result of the proposed South Atlantic Sale 43.

It is felt that a new refinery would not be built as a direct result of crude oil from the leasing area. Decisions to build new refineries are highly complex. They include consideration of demand, market location, supply of crude, availability and cost of capital, time for amortization, cost of crude, price of product, site availability, State and local receptivity to refinery development, and air and water quality standards. These factors are affected by regional and national concerns.

Currently, there is no fully integrated refinery in the South Atlantic. Refining activity is limited to the Standard Industrial Classifications sectors, paving and roofing materials (SIC 295), and miscellaneous products (SIC 299). A variety of factors, however, could result in a fully integrated refinery being built in the South Atlantic. If such a refinery is built a minimum capacity of 200,000 barrels of oil per day could be expected. A refinery in the area would have implications in our scenario development. Three possible futures are considered and are modeled in the South Atlantic; Base I is the future without a refinery, and Base II is the future with a refinery at Chatham County, GA. The specific assumptions concerning the refinery are included in Table II. Further discussion of Base III is included in Chapter IV.

One of the weaknesses of the model is the level of aggregation necessary in the industrial sectors. Because of the high level of demand for refinery products in the South Atlantic that is currently supplied by imports into the region, the model located new output in the region. This would be a logical step except that it avoided the threshold levels by locating most of the growth in Chatham County, Georgia, which already had a refining sector. Chatham's refining sector, however, is composed of paving and roofing materials and miscellaneous petroleum products. The level of growth in output predicted by the model would be excessive without a fully integrated refinery (a fully integrated refinery is a refinery that produces a full range of petroleum products). To correct this the level of output in refining was constrained in Chatham County to be directly proportional to the level of growth in output. It is hoped that this will allow the meeting of a level of demand for specialized petroleum products. In Base II investment capable of building a fully integrated 200,000 barrel/day refinery in Chatham County was added into the model in 1982 and the constraint on output removed. Three scenarios (A, B, and D) were developed under the assumption of no refinery and two scenarios (C and E) were developed with a refinery. For discussion of additional scenarios, see Chapter IV.

5) It was assumed that South Atlantic OCS production will replace imported crude oil in the United States.

Currently with no fully integrated refineries in the South Atlantic, oil imports consist mainly of final products such as gasoline. The only port that currently receives any crude imports is Savannah. Unless a new refinery is constructed, a large increase in crude imports would not be expected. Hence it was assumed that all oil produced in the scenarios without refining in the South Atlantic would go to the rest of the nation and reduce the level of foreign imports. This assumption is consistent with a policy of decreasing United States dependence on foreign sources of energy. This assumption will not decrease the level of economic activity in the counties which are now used as ports because the mode of transportation will be the same between foreign and OCS crude.

If a refinery is constructed in the South Atlantic, foreign crude would most likely constitute a large percent of the feed stock. Any OCS production would partly replace these imports. In Base

II and Base III crude is imported to feed the hypothetical refinery. In the scenarios that include the refinery, foreign imports are replaced by OCS production.

6) No deep water oil ports are assumed.

This assumption was made to allow the effects of offshore activity to be clearly analyzed, separating them from any effects a deep water port may have. A deep water oil port, if large enough, could reduce the cost of imported crude, hence the value of crude landed from the OCS.

7) A competitive cash bonus leasing system is assumed. A royalty rate of 1/6 of the wellhead price is assumed with Federal control of revenue.

This is the present system used most often by BLM. Some uncertainty exists in this area and until some alternative is decided upon, this assumption will be used. The economic model does not explicitly determine government revenue but does quantify government expenditure. The level of royalty payments by year assumed and used as input into the economic model is computed by multiplying the produced oil and gas specified for the different scenarios by the royalty rate and the appropriate price of the oil or gas. Produced oil and gas is discussed in the next section. This enters the model on the national level and is allocated back to the regions, partly on a fixed historical basis and partly by the level of personal income.

Coastal zone legislation recently signed by President Ford might increase the government expenditure levels in counties affected by OCS activities. This was not included into the model because it was not possible to access the monetary impacts at this time.

Resource Assumptions

All resource assumptions were developed by the United States Geological Survey. At our request these were developed as a low and a high estimate. Estimates of employment by activity identified by USGS were developed from estimates from the Offshore Operators Committee of the American Petroleum Institute. The resources estimates that we received from USGS are included as Appendix B. A brief summary of the basic assumptions is included below:

1) Total oil reserves are estimated to range from 0.282 to 1.009 billion barrels of oil. Oil production expressed as a stable daily production rate ranges from 56,000 to 170,000 barrels of oil per day. Table II shows the complete production schedule.
2) Total natural gas reserves are estimated to range from 1.890 to 6.810 trillion cubic feet. Expressed as a stable daily production rate, natural gas production ranges from 466 million cubic feet to 1,397 million cubic feet of gas per day. Table II shows the complete production schedule.
3) Exploration activity requires a maximum of 5-10 active drilling vessels per year. The total number of exploration wells ranges from 95–220. The scheduling of exploration activity is shown on Table II, along with additional assumptions on costs and employment.
4) Platforms required to totally develop the resource range from 10-25 (8 if no gas is produced). Development wells drilled range from 160 to 500 wells. Scheduling, costs, and employment assumptions are shown in Table II.

Estimates of offshore and onshore development requirements beyond these basic assumptions were refined, using the GS estimates, to scenario specific estimates and are discussed in the next section.

Scenario Development and Comparisons

After reviewing all of the above assumptions it was decided that the minimum number of scenarios that would be needed was four. This includes a high and low scenario with a refinery, and a high and low scenario without a refinery. It was decided that a fifth alternative should be examined. This alternative is the proposal for an offshore gathering, storage, and terminal facility with no oil coming onshore in the South Atlantic. The reader is referred to Table II for a complete list of all of the assumptions used in the scenarios. Additional scenarios are examined in Chapter IV. A description of the methodology used in the specific resource siting will be followed by a general overview of the base cases and scenarios.

One of the most important elements in the development of any scenario-specific assumptions is a knowledge of the location of the resources. A good knowledge of resource location will not be obtained until well into the exploratory activity. A good predictive rule of oil company behavior is that any development will follow a path calculated to maximize profits. This assumption can provide guidance in locating onshore development. For example, because of the expense of marine pipeline, an oil or gas pipeline will come ashore at the nearest environmentally and technologically feasible point.

Any analysis of the South Atlantic is complicated by the geographic spread of the tracts that are offered. Given the geographical dispersion of the tracts it was decided that some system of allocating resources would have to be determined. The method used located platforms (with only one platform located per block) and allocated

resources evenly between platforms. To locate platforms, all tracts in the sale were assigned sequential numbers determined by the number of nominations they had received. For example, a tract receiving six nominations might be numbered 100-105, while the next tract, which received two nominations, would be numbered 106-107. A drawing was made using a table of random numbers to determine both the location and timing of the resource development. This technique was used in all scenarios.

All employment and investment is assigned to the county that contains the operations base. When more than one operations base exists, platforms are assumed to be serviced by the nearest base and employment and investment are accordingly proportioned. Assigning investment to the operations base is a logical assumption because it approximates the point of delivery for offshore equipment. Assigning employment to the operations bases is not as good an assumption. The terms of employment very often are 7 days on, 7 days off, or some other on/off arrangement. For offshore workers residence in close proximity of work is not as important of a consideration as those with daily work schedules. Contacts with industry indicate that it is not uncommon for workers to live 250 miles away. Hence, our assumption will overestimate employment in these counties.

All investment costs do not include the costs of land on which the facility will be located. This is because cost of land is one of the variables that is used to determine the location of the industry in the output equations, hence the value of land enters independent of the facility cost.

Two base cases were developed. Base I is the case without a fully integrated refinery. Output in the existing petroleum refining sectors was constrained in Chatham County, Georgia, to be equal to a direct proportion of output (minus petroleum refining) predicted by an early run of the model. The constrained levels are shown in Table II.

Base II is the case with a new fully integrated refinery in the South Atlantic. The refinery was located in Chatham County, Georgia. Inputs to the Harris Model were based on a study done by the State of Georgia on potential refinery locations. The modeled refinery has a capacity of 200,000 barrels of oil throughput per day. Its costs were estimated at $400 million and with employment estimated at 550 persons. The constraints on refinery output were removed in the model upon completion of the refinery. Scenarios C and E are consistent with the refinery assumption, and Scenarios A, B, and C are consistent with no fully integrated refinery assumptions. A discussion of the scenarios follows.

Scenario A models the case where no oil production comes onshore in the South Atlantic and no gas production exists. The scenario was developed using the low resource estimates. It will have the least onshore impacts and as such represents the bottom line of the range of impacts from development. The scenario could have easily been based on the high resource estimates. The low resource scenario was chosen to provide the bottom figure for our range.

The low resource estimates indicate that the building of an oil or gas pipeline will be marginal unless the resources are geographically concentrated. For Scenario A we assumed that the gas resources were randomly distributed throughout the offered tracts. If this occurs, it will be uneconomical to build pipelines to shore and no gas production will occur.

The economics of oil production are not as dependent upon pipeline economics if the surface transportation of oil is allowed. For Scenario A, we assumed that oil resources were sufficiently concentrated to allow the building of a centralized gathering, and storage, tanker terminal. Inputs for the terminal were based on a similar proposal by Exxon for use offshore California. Conoco has also suggested that a similar system might be employed in the North Atlantic. With no major refinery in the South Atlantic the oil production is forecast to go to Mid-Atlantic or Gulf Coast refineries.

The decision not to produce gas was assumed to have no impact on the exploration activity. The number of platforms and development wells were scaled to reflect the lack of gas production. A detailed list of the specific assumptions and the scheduling of exploration and development is included in Table II and Table III shows total direct employment. A summary of the basic components follows:

1. An onshore operations base is established in Chatham County, Georgia, in 1977 which employs 103 people. Investment in pollution containment and pickup equipment occurs at the beginning of development phases of production.
2. A centralized gathering, storage, and treatment offshore terminal is constructed in 1985. All oil is tankered to domestic refineries outside the region. The offshore terminal employs 36 persons.

3. No production of natural gas occurs. Investment and employment have been scaled down from the low recovery estimates to reflect this.

All investment and employment has occurred in Chatham County, Georgia (Savannah). An analogy can be drawn between this run and the potential that because of resource location all investment and employment occurs in alternative metropolitan areas such as Duval County, Florida (Jacksonville), or Charleston County, South Carolina (Charleston).

Scenario B arbitrarily places all gas production in the northern tracts and all oil production in the southern tracts. This assumption allows an oil and gas pipeline to be an economical alternative. Specific assumptions on scheduling and investment are found in Table II and employment assumptions are found in Table III. A summary of the basic components follows:

1. An onshore operations base is established in Chatham County, Georgia in 1977 which employs 103 persons. Pollution containment and pickup equipment investment occurs at the beginning of the exploration and at the beginning of the development phases of production.
2. Initially oil is stored and tankered from individual platforms. A 65 mile major marine pipeline is constructed with a landfall in Duval Co., Fla., in 1985. Terminal facilities also constructed in 1985 cost $4,000,000. All oil is tankered outside the South Atlantic region. It was assumed that one half of the production would be tankered to refineries along the East Coast and one half of the production would be sent to the Gulf Coast refineries.
3. A 68 mile major marine gas pipeline is built in 1986 with a landfall in Charleston, S. C. It was assumed that another 5 miles of overland pipeline would be needed to transport the gas to the processing plant and tie in with existing distribution systems. A 500 mcf/day processing plant is built in 1985, coming on stream in 1986. The plant costs $40,000,000 and employs 25 persons.

Scenario C includes the same resource assumptions as Scenario B, i.e., gas in the northern sale area and oil in the southern sale area. In Scenario C, however, a fully integrated refinery has come on stream in Chatham County, Georgia in 1982. The existence of a refinery in the area implies that a major proportion of the OCS crude will remain in the area. In Scenario C we assumed that the oil would be transported to the refinery by pipeline. Detailed assumptions on scheduling and investment is in Table II and a summary of employment is in Table III. A summary of the major components follows:

1. An onshore operations base is established in Chatham County, Georgia in 1977 which employs 103 persons. Pollution containment and pickup equipment investment occurs at the beginning of the exploration and at the beginning of the development phases of production.
2. Initially oil is stored and tankered from individual platforms. In 1985, a major marine oil pipeline is constructed to the nearest point onshore and then overland to a refinery in Chatham County. The distance transversed was plotted on a map and then an additional 20% added to allow for right-of-way consideration. All investment occurs in 1985, pipeline investment by county follows:

County	Investment
Chatham, Ga.	$7,200,000
Brynn, Ga.	3,600,000
Glynn, Ga.	44,800,000
McIntosh, Ga.	13,800,000
Liberty, Ga.	2,400,000

A terminal and pumping station will be built in Glynn County in 1985 at the cost of $3,000,000. All oil produced goes to the refinery in Chatham Co., Ga. OCS oil replaces imported oil that is supplying the refinery's feed stock.
3. A 68 mile major marine gas pipeline is built in 1986 with a landfall in Charleston, S.C. It was assumed that another 5 miles of overland pipeline would be needed to transport the gas to the processing plant and tie in with existing distribution systems. A 500 mcf/day processing plant is built in 1985, coming on stream in 1986. The plant costs $40,000,000 and employs 25 persons.

Scenario D is based on the high resource estimates. No refinery is assumed. All resource assumptions are based directly on USGS estimates and stay constant between the Scenarios D and E. Specific resource assumptions are found in Table II along with assumptions on the scheduling of development and investment. Table III summarizes employment in this scenario. A summary of the scenario's basic components follows:

1. Oil resources are evenly divided between 21 oil platforms and gas resources are evenly divided between 4 gas platforms. To develop the resources three onshore operations bases were postulated as follows: Glynn County, Georgia in 1977; Charleston County, South Carolina in 1978, and Duval County, Florida in 1979. The exploration effort is divided evenly between the three bases development platforms and wells were allocated to the nearest operations base.

Investment in pollution containment and pickup equipment was determined by the scheduling of exploration and development phases. Investment occurs as follows:

Year	County	Investment
1977	Glynn, Georgia	$300,000
1978	Charleston, South Carolina	300,000
1981	Glynn, Georgia	470,000
	Charleston, South Carolina	470,000
1982	Duval, Florida	470,000

2. Initial oil production is stored on the platforms, gathered and tankered out of the area. After the completion of the oil pipelines (90 miles to Duval in 1985, and 65 miles to Charleston in 1988), oil is conveyed to onshore terminals via these pipelines. Terminal facilities cost $4,000,000 and are constructed in 1985 in Duval Co., Fla., and in 1988 in Charleston, County, S.C. All crude oil is tankered outside the South Atlantic region.
3. Two major marine gas pipelines, consisting of 82 miles to Duval County, Florida, and 70 miles to Charleston County, South Carolina, were constructed to two 700 mmcf/day gas

TABLE III Timing of Total Direct Nonconstruction Employment -
Total Offshore Employment Low Recovery - Sale 43

Year	Production 10^3 bld	Production 10^6 cf/d	Exploration Vessels	Employment	Development Rigs	Employment	Platforms	Employment	Total Offshore Employment
1976									-
1977			4	452					452
1978			5	565					565
1979			5	565					565
1980			3	339					339
1981			3	339	1	65			404
1982	3		2	226	3	195	1	22	443
1983	7		2	226	5	325	3	66	617
1984	11		2	226	8	520	5	110	856
1985	16		2	226	6	390	7	154	770
1986	23	200	1	113	4	260	8	176	549
1987	30	274	1	113	4	260	9	198	571
1988	37	342	1	113	1	65	10	220	398
1989	45	421	1	113	1	65	10	220	398
1990	56	466	1	113	1	65	10	220	398
1991	56	466			1	65	10	220	285
1992	56	466			1	65	10	220	285
1993	56	466			1	65	10	220	285
1994	56	466			1	65	10	220	285
1995	56	466			1	65	10	220	285
1996	56	466			1	65	10	220	285
1997	51	301			1	65	10	220	285
1998	45	181			1	65	10	220	285
1999	40	82			1	65	10	220	285
2000	25	41			1	65	8	176	241
2001	18	27			1	65	7	154	219
2002	10	11			1	65	3	66	131
2003	6	11			1	65	2	44	109
2004	5	8			1	65	2	44	109
2005	3	8			1	65	1	22	87
2006	3	8			1	65	1	22	87

TABLE III Timing of Total Direct Nonconstruction Employment -
Total Offshore Employment, High Recovery - Sale 43

Year	Production 10^3 bld	Production 10^6 cf/d	Exploration Vessels	Employment	Development Rigs	Employment	Platforms	Employment	Total Offshore Employment
1976									
1977			4	452					452
1978			10	1,130					1,130
1979			10	1,130					1,130
1980			10	1,130					1,130
1981			7	940	2	135			1,075
1982	8		5	565	5	325	2	44	934
1983	25		5	565	10	650	4	88	1,303
1984	41		5	565	14	910	6	132	1,607
1985	55		5	565	15	975	8	176	1,716
1986	77	701	3	339	12	780	13	286	1,405
1987	99	726	3	339	12	780	16	352	1,471
1988	134	726	3	339	12	780	19	418	1,537
1989	162	1,359	1	113	8	520	21	462	1,095
1990	167	1,397	1	113	5	325	23	506	944
1991	170	1,397	1	113	4	260	25	550	923
1992	170	1,397	1	113	2	130	25	550	793
1993	170	1,397			2	130	25	550	680
1994	170	1,397			2	130	25	550	680
1995	170	1,397			2	130	25	550	680
1996	170	1,375			2	130	25	550	680
1997	170	1,351			2	130	25	550	680
1998	170	1,351			2	130	25	550	680
1999	170	1,288			2	130	25	550	680
2000	151	740			2	130	23	506	636
2001	123	438			2	130	23	506	636
2002	71	129			2	130	20	440	570
2003	52	41			2	130	18	396	526
2004	38	19			2	130	15	330	460
2005	19	19			2	130	12	264	394
2006	14	11			2	130	10	220	350
2007	3	0			2	130	4	88	218

TABLE III Timing of Total Direct Nonconstruction Employment - Scenario A Sale 43 (Low Recovery)

Year	Offshore 1/ (exclud. Terminal)	Offshore Terminal	Office	Operation's Base	Total Employment Scenario A
1976	-				
1977	452		30	103	582
1978	565		30	103	698
1979	565		30	103	698
1980	339		30	103	472
1981	426		30	103	559
1982	487		30	103	620
1983	661		30	103	794
1984	683		30	103	816
1985	770	36	30	103	939
1986	427	36	30	103	596
1987	549	36	30	103	718
1988	354	36	30	103	523
1989	354	36	30	103	523
1990	354	36	30	103	523
1991	241	36	30	103	410
1992	241	36	30	103	410
1993	241	36	30	103	410
1994	241	36	30	103	410
1995	241	36	30	103	410
1996 2/	241	36	30	103	410

2/ Employment is only shown for the 20 years on which the model is run.
1/ Employment has been scaled to reflect no gas production.

TABLE III Timing of Total Direct Nonconstruction Employment - Scenario B Sale 43 (Low Recovery)

Year	Total Offshore	Office	Operation's Base	Gas Processing Plant	Pipeline Terminal and Tanker Port	Total Employment Scenario B
1976						
1977	452	30	103			585
1978	565	30	103			698
1979	565	30	103			698
1980	339	30	103			472
1981	404	30	103			537
1982	443	30	103			576
1983	617	30	103			750
1984	856	30	103			989
1985	770	30	103		13	916
1986	549	30	103	25	13	720
1987	571	30	103	25	13	742
1988	398	30	103	25	13	569
1989	398	30	103	25	13	569
1990	398	30	103	25	13	569
1991	285	30	103	25	13	456
1992	285	30	103	25	13	456
1993	285	30	103	25	13	456
1994	285	30	103	25	13	456
1995	285	30	103	25	13	456
1996*	285	30	103	25	13	456

* Employment is only shown for the 20 years on which the model is run.

TABLE III Timing of Direct Nonconstruction Employment - Scenario C Sale 43 (Low Recovery)

Year	Total Offshore	Office	Operation's Base	Gas Processing Plant	Oil Pipeline Terminal	Total Employment Scenario C	Refinery[1]
1976							
1977	452	30	103			585	
1978	565	30	103			698	
1979	565	30	103			698	
1980	339	30	103			472	
1981	404	30	103			537	
1982	443	30	103			576	550
1983	617	30	103			750	550
1984	856	30	103			989	550
1985	770	30	103		9	912	550
1986	549	30	103	25	9	716	550
1987	571	30	103	25	9	738	550
1988	398	30	103	25	9	565	550
1989	398	30	103	25	9	565	550
1990	398	30	103	25	9	565	550
1991	285	30	103	25	9	452	550
1992	285	30	103	25	9	452	550
1993	285	30	103	25	9	452	550
1994	285	30	103	25	9	452	550
1995	285	30	103	25	9	452	550
1996*	285	30	103	25	9	452	550

* Employment is only shown for the 20 years on which the model is run.
1 Refinery employment is not included in the total estimate because it is not generated by the OCS development.

TABLE III Timing of Direct Nonconstruction Employment - Scenario D Sale 43 (High Recovery)

Year	Total Offshore	Office	Operation's Base	Gas Processing Plant	Oil Terminals and Tanker Ports	Total Employment Scenario D
1976						
1977	452	30	103			585
1978	1,130	36	206			1,372
1979	1,130	42	309			1,481
1980	1,130	42	309			1,481
1981	1,075	42	309			1,426
1982	934	42	309			1,285
1983	1,303	42	309			1,654
1984	1,607	42	309			1,958
1985	1,716	42	309		13	2,080
1986	1,405	42	309	30	13	1,799
1987	1,471	42	309	30	13	1,865
1988	1,537	42	309	30	26	1,944
1989	1,095	42	309	60	26	1,532
1990	944	42	309	60	26	1,381
1991	923	42	309	60	26	1,360
1992	793	42	309	60	26	1,230
1993	680	42	309	60	26	1,057
1994	680	42	309	60	26	1,057
1995	680	42	309	60	26	1,057
1996*	680	42	309	60	26	1,057

* Employment is only shown for the 20 years on which the model is run.

TABLE III Timing of Direct Nonconstruction Employment - Scenario E Sale 43 (High Recovery)

Year	Total Offshore	Office	Operation's Base	Gas Processing Plant	Oil Pipeline Terminal	Total Employment Scenario E	Refinery[1]
1976							
1977	452	30	103			585	
1978	1,130	36	206			1,372	
1979	1,130	42	309			1,481	
1980	1,130	42	309			1,481	
1981	1,075	42	309			1,426	
1982	934	42	309			1,285	550
1983	1,303	42	309			1,654	550
1984	1,607	42	309			1,958	550
1985	1,716	42	309		17	2,084	550
1986	1,405	42	309	30	17	1,803	550
1987	1,471	42	309	30	17	1,869	550
1988	1,537	42	309	30	17	1,905	550
1989	1,095	42	309	60	17	1,523	550
1990	944	42	309	60	17	1,372	550
1991	923	42	309	60	17	1,351	550
1992	793	42	309	60	17	1,221	550
1993	680	42	309	60	17	1,108	550
1994	680	42	309	60	17	1,108	550
1995	680	42	309	60	17	1,108	550
1996*	680	42	309	60	17	1,108	550

* Employment is only shown for the 20 years on which the model is run.

1 Refinery employment is not included in the total estimate because it is not generated by the OCS development.

processing plants. Investment costs and employment by county and year are as follows:

Year	County	Investment	Employment
1985	Duval, Fla.	$60,000,000	30
1988	Charleston, S.C.	60,000,000	30

Scenario E is based on the high resource estimates and the refinery assumption. Resource, exploration, and initial development assumptions are the same as Scenario D. A refinery is assumed to be on stream in Chatham County, Georgia in 1982. A mainly marine pipeline connects the OCS production areas to the refinery. Detailed scheduling and investment assumptions are shown in Table II while a summary of employment assumptions are shown in Table III. A summary of the scenario's basic components follows:

1. Three onshore operations bases were postulated as follows: Glynn County, Georgia in 1977; Charleston County, South Carolina in 1978, and Duval County, Florida. The exploration effort is divided evenly between the three bases development platforms and wells were allocated to the nearest operations base.

Investment in pollution containment and pickup equipment was determined by the scheduling of exploration and development phases. Investment occurs as follows:

Year	County	Investment
1977	Glynn, Georgia	$300,000
1978	Charleston, South Carolina	300,000
1981	Glynn, Georgia	470,000
	Charleston, South Carolina	470,000
1982	Duval, Florida	470,000

2. Initial oil production is stored on the platforms, gathered, and tankered to the refinery in Chatham County, Georgia. After the completion of the oil pipeline in 1985 (176 miles to Chatham County) all oil is piped directly to the refinery. A pipeline terminal is built at the landfall; with a cost of $4,000,000. Oil imports to feed the 200,000 barrel/day refinery are shipped to Chatham County. OCS production replaces these imports.
3. Two gas pipelines, a 75 mile pipeline to Glynn County, Georgia and a 70 mile pipeline to Charleston County, South Carolina, connecting with two 700 mmcf/day gas processing plants are included in this scenario. Investment costs and employment by county and year are as follows:

Year	County	Investment	Employment
1985	Glynn, Ga.	$60,000,000	30
1988	Charleston, S.C.	60,000,000	30

Model Information

For each base case and scenario data has been obtained for the following levels of aggregation:

1. County (including independent cities)
2. State coastal regions
3. Mid-Atlantic coastal region as a whole
4. United States as a whole.

The county, State, and regional aggregations included only the following counties:

Florida	Georgia	North Carolina	South Carolina
Baker	Bryan	Brunswick	Beaufort
Clay	Camden	Columbus	Berkeley
Duval	Chatham	New Hanover	Charleston
Falgler	Effinghan	Pender	Colleton
Nassau	Glynn		Dorchester
Putnam	Liberty		Georgetown
St. Johns	Long		Hampton
	McIntosh		Harry
			Jasper
			Williamsburg

The value of output, along with employment, earnings, demand, value added, foreign exports and imports, and personal consumption expenditures is determined for 22 industrial sectors shown in Table I. Output is shown for the years 1975, 1976, 1980, 1984, 1988, 1992, and 1996.

Equipment purchasing sectors and construction sectors are shown in Table IV and Table V. The value of equipment purchases (12 categories) and construction (20 categories) is shown for all years 1976-1996. All output is in 1972 prices. Other output categories shown for 1975, 1976, 1980, 1984, 1988, 1992, and 1996 include:

Civilian Labor Force
Net Commuters
Civilian Persons Employed
Civilian Unemployment
Civilian Unemployment Rate
Population Density
Multi-Job Holders
Net Population Migration
Population Associated with Labor Force Surplus
Population
Personal Income
Earnings
Property Income
Social Insurance Payments
Transfer Payments
Agricultural Value of Land Per Acre
Federal Government Expenditure (Excl. Const. & Emp. Comp.)
State & Local Government Expenditure (Excl. Const. & Emp. Comp.)
Federal Government Purchases (Excl. Const.)
State and Local Government Purchases (Excl. Const.)
Personal Consumption Expenditures
Private Investment
Gross Regional Product
Per Capita Income
Total Supply
Total Demand
Domestic Output
Competing Imports
Noncompetitive Industry Imports
Noncompetitive Consumer Imports
Gross Foreign Exports
Value Added
Equipment Purchases
Construction
Federal Defense Expenditures

TABLE IV Equipment Purchasing Sectors

A	Farm (1), Meat Products (6), Tobacco (7), Dairy Products (62), Canned and Frozen Foods (63), Grain Mill Products (64), Bakery Products (65), Sugar (66), Confectionery (67), Beverages (68), Miscellaneous Foods (69)
B	Mining (2)
C	Oil and Gas Wells (3)
D	Construction (4)
E	Fabrics and Yarn (8), Rugs, Tire Cord (9), Apparel (10), Household Textiles and Upholstery (11)
F	Lumber and Productions Excluding Containers (12), Wooden Containers (13), Household Furniture (14), Office Furniture (15), Paper, Excluding Containers (16), Paper Containers (17)
G	Basic Chemicals (19), Drugs, Cleaning, and Toilet Items (21), Paint (22), Plastics and Synthetics (20), Rubber and Plastic (24)
H	Petroleum Refining (23)
I	Leather Tanning (25), Shoes and Other Leather Products (26), Glass and Products (27), Stone and Clay Products (28)
J	Iron and Steel (29)
K	Non Ferrous Metals (30), Metal Containers (31), Heating, Plumbing, Structural Metal (32), Stampings, Screw Machine Products (33), Hardware, Plating, Wire Products, and Valves (34)
L	Ordnance (5), Engines and Turbines (35), Farm Machinery and Equipment (36), Construction and Material Handling Equipment (37), Metal Working Machinery (38), Special Industrial Machinery (39), General Industrial Machinery (40), Machine Shops and Miscellaneous (41), Office and Computing Machines (42), Service Industry Machinery (43), Electric Apparatus and Motors (44), Household Appliancés (45), Electronic Components (48), Batteries, X-Ray and Engine Electrical Equipment (49), Motor Vehicles (50), Aircraft and Parts (51), Ships, Trains, and Cycles (52), Instruments (53), Optical and Photographic Equipment (54), Miscellaneous Manufacturing (55)
M	Transportation (56)
N	Printing and Publishing (18), Communication (57)
O	Utility (58)
P	Trade (59)
Q	Finance and Insurance (60)
R	Service (61)

* All numbers in parenthesis refer to Harris Model industrial sectors

Source: Harris 1972

Table V Construction

A	Residential (1), Additions and Alterations to Residences (2), Nonhousekeeping Residential Construction (3)
B	Offices (5), Stores, Restaurants and Garages (6), Miscellaneous Nonresidential Buildings (10), All Other Private Construction (17)
C	Industrial (4)
D	Religious (7)
E	Educational (8)
F	Hospital and Institutional (9)
G	Farm Construction (11)
H	Oil and Gas Well Drilling and Exploration (12)
I	Railroad (13)
J	Highway (18)
K	Telephone (14)
L	Electric Utility (15)
M	Gas and Petroleum Pipelines (16)
N	Sewer Systems (21), Water Systems (22)
O	Conservation (20)
P	Public Residential (23)
Q	Public Industrial Construction (24)
R	Public Educational (25)
S	Public Hospital (26)
T	Military (19), Other Public Structures (27), Miscellaneous Public (28)

* All numbers in parenthesis refer to Harris Model Industrial sectors

Source: Harris, 1972.

CHAPTER III

Results of the Initial Harris Model Scenarios

The approach followed in presenting the scenario results will concentrate primarily on the changes induced in industrial sectors as a result of the proposed OCS leasing program This will be followed by a discussion of some of the other social and economic variables predicted by the model.

There are two reasons for this approach. First, the approach follows the logic of the model which uses changes in industrial output as the primary determinant of changes in other economic variables. Second, the purpose of this paper is to provide a technical guide to the Harris Model's South Atlantic application. Hence, this chapter will focus on the cause and effect relationships between direct oil and gas development and induced changes in other economic variables.

A more generalized impact analysis using the results of the model is found in the main body of the *Draft Environmental Statement, Proposed Sale 43*. The reader is referred to the section on economic impacts for a more detailed discussion of the predicted variables

Table VI shows output by industrial sector expressed as a percentage of the total for the South Atlantic coastal region and the U.S. for the years 1976 and 1996. Table VII and Table VIII show a similar breakdown for the coastal region of each state. Major differences in the structures of the two economies are found in the sectors of lumber and wood processing (percentage output in the South Atlantic coastal region is 11.0%, compared to 3.2% in the U.S.) and machinery and miscellaneous manufacturing (13.9% in the U.S., compared to 2.8% in the South Atlantic). The South coastal areas have a greater than average percentage of output in transportation and wholesale trade reflecting its position as an import center for the interior regions and in agricultural and food processing, forestry and fisheries, and lumber and wood processing reflecting the region's agricultural base. A greater than average percentage of output also was shown in the chemical and plastics sector. The region's below average percentages in petroleum refining (Base I only), iron and steel, other metals, and machinery and miscellaneous manufacturing indicate a lack of a strong industrial base.

Output sectors in 1976 show a great deal of variation between the states. Apparel and textile sectors are large in North and South Carolina while small in the rest of the region. Although lumber and wood processing represents a greater precent of output in all of the South Atlantic states than the U.S. (3.2%), it is particularly large in Georgia (18.0%) and North Carolina (10.5%). Georgia has a large chemical and plastics sector (17.4%). The wholesale trade (11.2%) and transportation (5.0%) sectors in Florida reflect the importance of the port at Jacksonville. Finance, insurance and real estate sectors are larger in Florida (15.1%) and South Carolina (22.5%) than the national average (13.2%) while the same sectors are smaller than average in Georgia (6.4%) and North Carolina (8.8%).

Changes that occurred between 1976 and 1996 were relatively minor with only a few sectors showing a major change. Florida's agricultural and food processing, lumber and wood products, and chemicals and plastics increase while finance, insurance and real estate and retail stores decline. In Georgia, the most significant changes in Base I occur in the decline of the forestry and fishery and lumber and wood processing sectors and the increase in the chemical and plastic sectors. In Base II, petroleum refining increases from 4.3% to 12.4% of total output. Trends in the other sectors are accentuated. North Carolina's agricultural and food processing sectors decline dramatically while apparel and textiles, lumber and wood processing, and machinery and miscellaneous manufacturing all show increases. The financial, insurance and real estate sector in South Carolina grows to 31.2% of total output compared to a 5.6% average in the South Atlantic coastal area and a national average of 13.7% sectors which show decline percentages in South Carolina are agricultural and food processing, forestry and fisheries, lumber and wood processing and chemical and plastics.

One of the most striking results apparent from an examination of Base I and Base II is the lack of economic linkages between the coastal counties. Although the location of a refinery in Chatham County had important effects within the county, effects on adjacent counties or other coastal counties were minor. Impacts from OCS related developments behaved in a similar fashion. This implies that trade probably moves from coastal areas to areas inland rather than

Table VI

Comparison of U.S. and South Atlantic Coastal Region's Economies - Percent Output

	1976		1996		
Industry Grouping	USA Base I	South Atlantic Base II	USA*	South Atlantic Basé I	Base II
Ag. & Food Process.	11.2	13.2	9.5	11.7	11.5
Forestry & Fishing	.1	.5	.0	.1	.1
Non Petrol Mining	.7	.1	.7	.0	.0
Petroleum Mining	.8	.0	.8	.0	.0
Apparel & Textiles	3.3	3.7	3.0	4.3	4.2
Lumber & Wood Prod.	3.2	11.0	3.0	10.0	9.9
Chemical & Plastics	4.5	6.4	5.6	8.7	8.5
Petroleum Refining	1.8	1.3	1.7	1.3	3.0
Leather, Glass, & Stone	1.4	1.5	1.3	1.5	1.5
Iron & Steel	2.1	.9	1.5	.9	.9
Other Metals	3.7	1.3	3.3	1.2	1.2
Machinery & Misc. Mfg.	13.9	2.8	14.5	2.5	2.5
Transportation	3.3	4.1	3.6	4.2	4.2
Communications	3.6	3.4	3.9	3.7	3.6
Utility	3.4	2.4	3.3	2.1	2.1
Wholesale Trade	5.0	7.1	5.6	7.4	7.3
Fin. Ins., & Real Estate	13.2	14.7	13.7	15.9	15.6
Amusement & Service	2.1	2.7	1.9	2.1	2.1
Retail Stores	12.2	11.8	12.9	11.8	11.6
Medical & Ed. Inst.	4.8	3.9	5.0	4.3	4.2
Auto. Dealers & Service	2.7	3.9	2.6	3.4	3.4
Construction	3.0	3.4	2.7	2.7	2.6
Total	100.0	100.0	100.0	100.0	100.0

* No changes occur in USA percentages between Base I and II.

Table VII

Comparison of South Atlantic States Costal Economies - 1976 Percent Output

	State Costal Regions				
Industry Grouping	Florida	Georgia	North Carolina	South Carolina	South Atlantic
Ag. & Food Processing	13.8	10.7	12.6	14.4	13.2
Forestry & Fisheries	.4	.6	.2	.6	.5
Non Petrol. Mining	.1	.0	.0	.1	.1
Petroleum Mining	.0	.0	.0	.0	.0
Apparel & Textiles	.3	.8	13.4	7.6	3.7
Lumber & Wood Prod.	9.3	18.0	10.5	8.7	11.0
Chemical & Plastics	2.4	17.4	9.8	3.2	6.4
Petroleum Refining	.5	4.2	.0	.9	1.3
Leather, Glass & Stone	1.2	2.4	.9	1.5	1.5
Iron & Steel	.8	.4	.0	1.7	.9
Other Metals	1.5	1.6	2.4	.4	1.3
Machinery & Misc. Mfg.	2.0	2.8	4.4	3.5	2.8
Transportation	5.0	3.8	4.7	2.8	4.1
Communications	4.2	2.6	3.4	2.6	3.4
Utility	2.2	2.0	3.3	2.4	2.4
Wholesale Trade	11.2	4.0	4.6	4.0	7.1
Fin. Ins. & Real Estate	15.1	6.4	8.8	22.5	14.7
Amusement & Service	3.2	2.5	1.8	2.4	2.7
Retail Stores	13.8	10.1	10.1	10.4	11.8
Medical & Ed. Inst.	4.7	2.7	3.5	3.7	3.9
Auto Dealers & Service	4.8	3.3	3.0	3.4	3.9
Construction	3.5	3.6	2.7	3.4	3.4
Total	100.0	100.0	100.0	100.0	100.0

Table VIII

Comparison of South Atlantic States Costal Economies - 1996
Percent Output

	Base I					Base II				
Industry Grouping	Florida	Georgia	North Carolina	South Carolina	South Atlantic	Florida	Georgia	North Carolina	South Carolina	South Atlantic
Ag & Food Processing	14.7	10.6	5.7	10.4	11.7	14.7	9.6	5.7	10.4	11.5
Forestry & Fisheries	.1	.1	.0	.1	.1	.1	.1	.0	.1	.1
Non Petrol. Mining	.1	.0	.0	.0	.0	.1	.0	.0	.0	.0
Petroleum Mining	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Apparel & Textiles	.2	1.9	16.3	7.6	4.3	.2	1.7	16.3	7.6	4.2
Lumber & Wood Prod.	10.7	11.0	13.6	7.3	10.0	10.7	10.0	13.6	7.3	9.9
Chemical & Plastic	4.4	27.9	10.1	1.8	8.7	4.4	25.6	10.1	1.8	8.5
Petroleum Refining	1.8	4.3	.0	.4	1.3	.8	12.4	.0	.4	3.0
Leather, Glass & Stone	1.5	2.0	.8	1.5	1.5	1.5	1.8	.8	1.5	1.5
Iron & Steel	.9	.5	.0	1.4	.9	.9	.4	.0	1.4	.9
Other Metals	1.6	1.7	1.2	.4	1.2	1.6	1.6	1.2	.4	1.2
Machinery & Misc. Mfg.	1.6	1.5	8.0	2.5	2.5	1.6	1.4	8.0	2.5	2.5
Transportation	5.4	3.8	4.7	2.8	4.2	5.4	3.5	4.7	2.8	4.2
Communications	4.8	3.5	3.4	2.3	3.7	4.8	3.2	3.4	2.3	3.6
Utility	2.3	1.9	1.5	2.3	2.1	2.3	1.7	1.5	2.3	2.1
Wholesale Trade	11.9	4.3	4.8	4.1	7.4	11.9	4.0	4.8	4.1	7.3
Fin., Ins. & Real Estate	12.9	3.2	6.7	31.2	15.9	12.9	2.9	6.7	31.2	15.6
Amusement & Service	2.8	2.2	1.2	1.5	2.1	2.8	2.0	1.2	1.5	2.1
Retail Stores	11.2	11.2	14.1	12.4	11.8	11.2	10.2	14.1	12.4	11.6
Medical & Ed. Inst.	5.4	2.5	3.2	4.3	4.3	5.4	2.3	3.2	4.3	4.2
Auto Dealers & Service	4.2	3.0	2.5	2.9	3.4	4.2	2.8	2.5	2.9	3.4
Construction	2.7	3.0	2.1	2.6	2.7	2.7	2.7	2.1	2.6	2.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

between coastal counties. It should be noted however, that the transportation algorithms only consider highway and rail transportation rates. If shipping rates are lower than the alternative rail or highway transportation rates between coastal counties, linkages predicted by the model might be considerably understated.

Changes in the value of output by the industry sector for the South Atlantic coastal region are shown in Table IX. Percentage changes from the base value of the sector are also shown. Changes in the value of petroleum mining dominates the changes in the value of output. Value of petroleum mining is an input variable into the model and reflects the discoveries on the OCS. Value of output in the construction sector is partially specified as an input variable and partially represents induced development. The only other industrial sector which shows large induced increases when compared to the base level is petroleum refining. Increases are largest in the no refinery scenarios, where as a percentage of the original base, induced development represented as much as a 24% increase. The petroleum refinery sector will be discussed in greater detail below.

Other sectors which showed lesser changes over the base amounts are machinery and miscellaneous manufacturing and transportation and wholesale and retail trade. Increases in wholesale and retail trade were estimated at approximately 20 million dollars although it represented less than a 1% increase over the base level.

Table X shows changes in total value of output minus the value of petroleum mining by county. Petroleum mining was excluded to give some approximation of induced output. The value is an imperfect approximation however, because it does have some direct (versus induced) elements included in the construction sectors.

The change in induced output is less than 1% in all counties in all years modeled with the exception of Glynn County, Georgia. Glynn County base output is smaller than most of the areas that have direct OCS development. Induced output in 1996 accounted for 2% of total output in Scenario D and 3% of total output in Scenario E.

The lack of economic linkages between counties is shown in Table X. When output is compared to scenario inputs, it can be shown that changes in output occur almost exclusively in counties which received input specifications. Changes that occur in other counties are small in both actual magnitude, with most changes being under $500,000 and no change being over $1,000,000.

The number of jobs created by OCS development is shown in Table XI. The sectors which showed the greatest increase in jobs are the construction, wholesale and retail trade, transportation, machinery and miscellaneous manufacturing, state and local governments, and petroleum mining. Increases in jobs in wholesale and retail trade and state and local government are primarily induced by OCS generated increases in population and personal income. Jobs in transportation, machinery and miscellaneous manufacturing and petroleum mining reflect changing industrial structures. Jobs in construction are induced by both factors.

Jobs were not summarized by county or state. The same distribution that occurred in output also occurs in jobs. Counties that received direct inputs represented most of the increase in jobs with other counties accounting for a very small percent of the created jobs.

Civilian persons employed is derived from number of jobs by adjusting jobs by the number of multi-job holders. The civilian labor force is derived by adjusting the employment by the number of commuters. A discussion of the predicted values for these variables are included in the main body of the impact statement.

Two industrial sectors are treated in greater detail below. These are petroleum refining, which had a large increase in value of output and transportation which had substantial increases in number of jobs. Other sectors which had large increases can be explained directly by the specification of inputs (construction) or changes in population and the level of personal income (wholesale and retail trade, and state and local governments) and are not treated separately.

The value of output in petroleum refining is shown by state and selected county in Table XII. No refining activity was specified in the scenarios and all refining activity shown should be considered as induced by OCS development. An investment in refinery capacity was specified in Base II of $400 million (200,000 barrel/day refinery). In the model the investment shows up as an approximate $500 million value of output. OCS generated refining output reaches a maximum value of $85 million, which indicates that the refining capacity generated is small.

TABLE IX
Value of Output Induced by OCS Development in the
South Atlantic 1984

Value of Output ($1000's)	Base Base I	Scenario A (Low)	%	Minus B (Low)	%	Base D (High)	%	Base Base II	Scenario C (Low)	%	Minus Base E (High)	%
Ag. & Food Process	2,277,306	31		30		170		2,277,302	31		163	
Forestry & Fisheries	52,607	0		0		0		52,627	0		0	
Non Petrol. Mining	8,234	0		0		0		8,234	0		0	
Petroleum Mining	412	0		23,097	5606.1	-4	-1.0	412	23,587	5725.0	88,448	21468.0
Apparel & Textiles	727,595	3		2		2		727,597	2		1	
Lumber & Wood Prod.	1,968,646	11		-1		13		1,968,629	1		12	
Chemical & Plastics	1,390,126	91		89		176		1,390,840	88		199	
Petroleum Refining	235,211	4		2,597	1.1	10		733,293	2		9	
Leather, Glass & Stone	290,581	149	.1	66		91		290,931	67		98	
Iron & Steel	173,414	217	.1	218	.1	293	.2	173,457	218	.1	296	.2
Other Metals	243,948	203		106		176		245,536	105		180	
Machinery & Misc. Mfg.	460,095	1,636	.4	1,642	.4	4,416	1.0	460,066	1,618	.4	4,414	1.0
Transportation	766,594	3,873	.5	3,060	.4	5,203	.7	767,968	3,051	.4	7,057	.9
Communications	623,598	132		129		541	.1	623,471	133		511	.1
Utility	412,798	9		55		312	.1	412,806	8		310	.1
Wholesale Trade	1,327,432	5,880	.4	3,929	.3	7,914	.6	1,329,521	3,898	.3	7,932	.5
Fin., Ins., & Real Estate	2,773,971	38		35		-49		2,774,011	40		-49	
Amusement & Service	441,636	170		164		283	.1	441,749	163		268	.1
Retail Stores	2,121,864	6,967	.3	4,639	.2	9,428	.4	2,124,365	4,599	.2	9,452	.4
Medical & Ed. Inst.	745,944	343		332		696	.1	746,217	331		687	.1
Auto Dealers & Service	679,076	1,966	.3	1,384	.2	2,805	.4	679,968	1,374	.2	2,849	.4
Construction	591,482	25,368	4.3	16,171	2.7	34,809	5.9	593,590	16,158	2.7	35,128	5.9

TABLE IX (Continued)
Value of Output Induced by OCS Development in the
South Atlantic 1988

Value of Output ($1000's)	Base Base I	Scenario A (Low)	%	Minus B (Low)	%	Base D (High)	%	Base Base II	Scenario C (Low)	%	Minus Base E (High)	%
Ag. & Food Process	2,593,324	67		80		377		2,593,327	61		203	
Forestry & Fisheries	41,597	0		0		0		41,597	0		0	
Non Petrol. Mining	8,696	0		0		1		8,696	0		1	
Petroleum Mining	614	-1		187,323	30508.6	721,900	117573.3	612	* 192,069	31383.8	720,861	117787.7
Apparel & Textiles	864,723	5		5		8		864,731	6		9	
Lumber & Wood Prod.	2,225,551	-3		4		85		2,225,557	2		52	
Chemical & Plastics	1,694,844	123		290		707		1,697,095	200		767	
Petroleum Refining	271,580	5		22,403	8.2	10,487	3.9	769,544	6,812	2.5	3,668	1.4
Leather, Glass & Stone	332,663	206	.1	225	.1	434	.1	333,126	208	.1	325	.1
Iron & Steel	199,384	330	.2	690	.3	991	.5	199,446	537	.3	941	.5
Other Metals	273,750	400	.1	567	.2	1,125	.4	275,548	508	.2	1,264	.5
Machinery & Misc. Mfg.	521,863	2,484	.5	2,697	.5	10,358	2.0	521,757	2,503	.5	9,838	1.9
Transportation	892,607	1,778	.2	5,143	.6	25,025	2.8	894,650	5,044	.5	23,136	2.6
Communications	735,461	290		557	.1	1,038	.1	735,121	390	.1	101	
Utility	468,132	15		622	.1	1,463	.3	468,177	231		1,172	.3
Wholesale Trade	1,548,321	2,717	.2	2,039	.1	15,735	1.0	1,551,440	1,711	.1	12,892	.8
Fin., Ins., & Real Estate	3,267,218	73		3		-270		3,267,618	105		-501	
Amusement & Service	488,483	342	.1	361	.1	600	.1	488,649	314	.1	386	.1
Retail Stores	2,458,508	3,109	.1	2,320	.1	17,855	.7	2,462,014	1,956	.1	15,421	.6
Medical & Ed. Inst.	881,094	716	.1	898	.1	1,705	.2	881,586	820	.1	1,457	.2
Auto Dealers & Service	766,238	1,185	.2	1,281	.2	5,922	.8	767,552	1,149	.2	5,401	.7
Construction	642,972	5,087	.8	6,260	1.0	59,883	9.3	645,200	6,178	1.0	42,112	6.5

*31383.8

TABLE IX (Continued)
Value of Output Induced by OCS Development in the
South Atlantic 1992

Value of Output ($1000's)	Base Base I	Scenario A (Low)	%	Minus B (Low)	%	Base D (High)	%	Base Base II	Scenario C (Low)	%	Minus Base E (High)	%
Ag. & Food Process	2,932,263	99		120		463		2,932,317	89		22	
Forestry & Fisheries	33,563	0		0		0		33,563	0		0	
Non Petrol. Mining	9,188	0		0		0		9,188	0		0	
Petroleum Mining	884	0		267,733	30286.5	809,407	91561.9	880	268,605	30385.2	808,555	91465
Apparel & Textiles	1,025,486	9		9		12		1,025,500	10		13	
Lumber & Wood Prod.	2,509,473	1		12		46		2,509,537	18		67	
Chemical & Plastics	2,043,133	164		633		1,791	.1	2,047,075	418		1,886	.1
Petroleum Refining	307,756	6		52,489	17.1	42,764	13.9	805,627	21,754	2.7	21,087	2.6
Leather, Glass & Stone	378,913	231	.1	347	.1	805	.2	379,491	324	.1	594	.2
Iron & Steel	224,104	382	.2	782	.3	1,530	.7	224,184	625	.3	1,320	.6
Other Metals	307,206	454	.1	666	.2	1,393	.5	309,215	548	.2	1,600	.5
Machinery & Misc. Mfg.	602,784	3,191	.5	3,532	.6	13,624	2.3	602,583	2,980	.5	12,828	2.1
Transportation	1,033,004	1,657	.2	8,154	.8	21,634	2.1	1,035,258	7,747	.7	21,090	2.0
Communications	869,298	406		931	.1	1,761	.2	869,078	439	.1	-454	-.1
Utility	528,450	21		1,734	.3	4,471	.8	528,573	791	.1	3,310	.6
Wholesale Trade	1,798,620	2,549	.1	4,160	.2	7,939	.4	1,802,072	3,547	.2	7,114	.4
Fin., Ins., & Real Estate	3,827,467	119		-168		-700		3,828,512	-17		-1,015	
Amusement & Service	540,403	458	.1	536	.1	811	.2	540,643	386	.1	100	
Retail Stores	2,856,495	2,816	.1	4,630	.2	9,203	.3	2,859,810	3,760	.1	7,828	.3
Medical & Ed. Inst,	1,033,633	1,000	.1	1,323	.1	2,927	.3	1,034,418	1,170	.1	2,150	.2
Auto Dealers & Service	861,943	1,176	.1	2,401	.3	5,612	.7	863,452	2,169	.3	5,436	.6
Construction	697,181	1,811	.3	3,824	.5	8,696	1.2	699,393	3,572	.5	8,555	1.2

TABLE IX (Continued)
Value of Output Induced by OCS Development in the
South Atlantic 1996

Value of Output ($1000's)	Base Base I	Scenario A (Low)	%	Minus B (Low)	%	Base D (High)	%	Base Base II	Scenario C (Low)	%	Minus Base E (High)	%
Ag. & Food Process	3,282,898	126		176		490		3,282,317	144		-325	
Forestry & Fisheries	26,444	0		0		0		26,444	0		0	
Non Petrol. Mining	9,629	0		0		0		9,629	0		0	
Petroleum Mining	1,260	-1		267,785	21252.8	802,341		1,252	268,658	21458.3	801,544	64021.1
Apparel & Textiles	1,211,269	12		14		18		1,211,290	15		21	
Lumber & Wood Prod.	2,815,806	6		35		58		2,815,943	57		114	
Chemical & Plastics	2,433,581	218		1,135		3,074	.1	2,439,316	681		3,220	.1
Petroleum Refining	359,492	9		84,727	23.6	79,225	22.0	857,276	37,805	4.4	41,249	4.8
Leather, Glass & Stone	428,292	251	.1	487	.1	1,167	.3	428,985	455	.1	852	.2
Iron & Steel	247,007	415	.2	857	.3	1,721	.7	247,105	694	.3	1,474	.6
Other Metals	343,761	510	.1	821	.2	1,629	.5	345,984	599	.2	1,789	.5
Machinery & Misc. Mfg.	700,595	3,622	.5	4,132	.6	15,567	2.2	700,307	3,282	.5	14,635	2.1
Transportation	1,189,262	1,862	.2	8,729	.7	23,105	1.9	1,191,700	8,111	.7	22,159	1.9
Communications	1,024,987	503		1,591	.2	2,619	.3	1,025,084	803	.1	-104	
Utility	592,262	24		3,050	.5	7,368	1.2	592,435	1,461	.2	5,327	.9
Wholesale Trade	2,077,879	2,878	1.4	5,106	.2	10,504	.5	2,081,653	4,163	.2	9,054	.4
Fin., Ins., & Real Estate	4,445,558	162		-169		-1,039		4,447,482	63		-1,121	
Amusement & Service	596,586	570	.1	883	.1	1,287	.2	597,035	529	.1	57	
Retail Stores	3,316,866	3,090	.1	5,469	.2	11,897	.4	3,319,882	4,023	.1	9,372	.3
Medical & Ed. Inst,	1,202,329	1,285	.1	1,837	.2	3,958	.3	1,203,477	1,604	.1	2,770	.2
Auto Dealers & Service	964,476	1,287	.1	3,137	.3	7,584	.8	966,163	2,777	.3	7,143	.7
Construction	752,858	1,849	.2	4,107	.5	7,122	.9	755,065	3,719	.5	6,749	.9

TABLE X
Value of Output Induced by OCS Development - 1984
(Total Minus Value of Output in Petroleum Mining)

County, State	Base I	Scenario A (Low)	Minus B (Low)	Base D (High)	Base II	Scenario C (Low)	Minus Base E (High)
Baker	23,277	4	4	6	23,279	4	6
Clay	222,663	0	1	0	222,666	1	0
Duval	6,456,467	282	3,636	18,818	6,456,422	226	18,701
Flagler	30,945	2	2	2	30,947	2	2
Nassau	241,828	0	1	0	241,832	2	0
Putnam	583,819	-3	-1	-5	583,826	0	-5
St. Johns	180,971	8	8	16	180,978	8	15
Florida	7,739,971	291	3,650	18,836.99	7,739,949	243	18,720
Bryan	23,618	8	8	15	24,794	9	15
Camden	85,356	-1	-1	-2	85,357	-1	-2
Chatham	2,612,552	46,417	30,693	874	3,122,502	31,327	3,200
Effingham	54,521	7	6	10	54,502	7	11
Glynn	685,862	53	19	23,646	685,871	19	23,644
Liberty	78,248	7	6	9	78,249	6	9
Long	15,422	4	4	8	15,400	5	8
Mc Intosh	22,312	4	4	8	22,315	5	8
Georgia	3,577,891	46,499	30,740	24,568	4,087,821	31,376	26,891
Brunswick	149,150	10	10	17	149,159	10	16
Columbus	431,184	4	3	4	431,187	4	4
New Hanover	1,180,116	27	16	21	1,180,120	18	22
Pender	91,217	0	0	0	91,219	0	0
North Carolina	1,851,667	41	29	42	1,851,685	31	42
Beaufort	709,019	25	24	32	709,029	24	32
Berkeley	249,235	-2	-1	-3	249,236	-1	-3
Charleston	2,115,254	212	179	23,772	2,115,283	182	23,795
Colleton	259,561	-5	-3	-7	259,562	-2	-6
Dorchester	199,179	3	2	2	199,184	3	3
Georgetown	368,910	0	0	1	368,910	1	2
Hampton	156,960	0	0	-1	156,961	0	-1
Horry	768,892	23	20	31	768,910	22	32
Jasper	55,806	2	2	5	55,809	3	5
Williamsburg	260,245	1	3	7	260,248	5	4
South Carolina	5,143,060	262	228	23,840	5,143,133	235	23,861
South Atlantic	18,312,588	47,093	34,647	67,286	18,822,587	31,885	69,518

TABLE X (cont.)
Value of Output Induced by OCS Development - 1988
(Total Minus Value of Output in Petroleum Mining)

County, State	Base I	Scenario A (Low)	Minus B (Low)	Base D (High)	Base II	Scenario C (Low)	Minus Base E (High)
Baker	26,071	6	6	8	26,079	5	7
Clay	262,870	2	3	-6	262,879	4	3
Duval	7,350,721	66	20,391	51,653	7,350,700	144	25,503
Flagler	35,007	3	4	6	35,020	6	8
Nassau	286,163	5	8	1	286,195	12	14
Putnam	717,738	11	15	-13	717,779	20	12
St. Johns	214,279	14	20	30	214,346	28	49
Florida	8,892,850	105	20,445	51,678	8,892,998	220	25,596
Bryan	25,036	19	22	32	26,266	241	50
Camden	93,106	0	1	-3	93,112	2	0
Chatham	3,004,514	18,513	17,932	1,077	3,518,973	20,110	10,969
Effingham	62,230	11	10	15	62,188	15	27
Glynn	765,409	15	16	22,751	765,435	94	35,620
Liberty	92,155	3	4	11	92,164	-8	12
Long	20,863	11	10	18	20,826	16	26
Mc Intosh	23,175	16	17	27	23,202	-28	30
Georgia	4,086,487	18,589	18,015	23,930	4,601,000	20,441	46,734
Brunswick	172,539	15	19	26	172,605	28	45
Columbus	486,003	5	6	6	486,024	9	14
New Hanover	1,360,578	25	34	55	1,360,657	47	85
Pender	100,362	1	1	-1	100,368	1	0
North Carolina	2,119,482	45	61	86	2,119,653	86	146
Beaufort	892,019	24	19	23	892,079	20	23
Berkeley	284,427	0	0	-7	284,434	2	-3
Charleston	2,488,433	118	7,843	77,757	2,488,626	7,864	46,012
Colleton	312,989	1	2	-12	312,998	3	-4
Dorchester	232,585	4	8	5	232,635	15	22
Georgetown	428,854	3	3	14	428,865	6	6
Hampton	168,007	1	1	-1	168,009	2	1
Horry	911,613	31	39	50	911,739	54	87
Jasper	64,663	8	11	11	64,692	15	19
Williamsburg	295,213	-1	-1	-4	295,311	10	8
South Carolina	6,078,803	189	7,926	77,836	6,079,389	7,989	46,170
South Atlantic	21,177,620	18,928	46,447	153,530	21,693,039	28,737	118,645

TABLE X (cont.)
Value of Output Induced by OCS Development - 1992
(Total Minus Value of Output in Petroleum Mining)

County, State	Base I	Scenario A (Low)	Minus B (Low)	Base D (High)	Base II	Scenario C (Low)	Minus Base E (High)
Baker	29,246	22	25	40	29,261	27	47
Clay	305,315	0	4	7	305,334	6	16
Duval	8,338,817	88	39,236	69,090	8,338,894	209	16,925
Flagler	39,005	4	6	11	39,020	7	14
Nassau	336,031	12	27	54	336,111	34	83
Putnam	866,406	17	36	60	866,503	46	102
St. Johns	251,004	20	53	105	251,160	67	169
Florida	10,165,824	163	39,386	69,367	10,166,282	397	17,357
Bryan	27,069	45	79	129	28,179	231	228
Camden	104,552	1	4	6	104,565	5	11
Chatham	3,451,952	15,935	16,719	1,277	3,968,623	19,450	13,271
Effingham	72,606	11	15	31	72,566	23	51
Glynn	850,989	14	25	15,394	851,038	250	27,192
Liberty	107,948	5	10	23	107,968	3	31
Long	28,447	17	25	51	28,421	36	80
Mc Intosh	25,612	26	33	57	25,671	-87	71
Georgia	4,669,174	16,054	16,911	16,969	5,186,182	19,910	40,934
Brunswick	199,053	21	51	94	199,206	64	156
Columbus	549,384	7	21	33	549,437	21	48
New Hanover	1,571,589	37	90	166	1,571,814	116	280
Pender	110,655	1	5	29	110,688	7	32
North Carolina	2,430,681	65	168	321	2,431,145	207	515
Beaufort	1,098,232	28	58	97	1,098,356	70	152
Berkeley	324,695	-1	4	8	324,713	5	15
Charleston	2,929,938	163	29,381	37,630	2,930,335	29,475	33,919
Colleton	373,967	5	23	47	374,034	30	84
Dorchester	267,039	5	31	60	267,154	43	113
Georgetown	494,352	3	9	15	494,377	12	27
Hampton	181,827	2	3	6	181,833	3	8
Horry	1,074,000	40	96	187	1,074,283	124	302
Jasper	75,088	14	29	47	75,168	37	80
Williamsburg	336,429	8	15	27	336,503	18	30
South Carolina	7,155,566	266	29,650	38,126	7,156,757	29,817	34,730
South Atlantic	24,421,244	16,548	86,115	124,782	24,940,363	50,332	93,534

TABLE X (cont.)
Value of Output Induced by OCS Development - 1996
(Total Minus Value of Output in Petroleum Mining)

County, State	Base I	Scenario A (Low)	Minus B (Low)	Base D (High)	Base II	Scenario C (Low)	Minus Base E (High)
Baker	32,691	35	41	66	32,713	41	75
Clay	349,865	1	7	13	349,893	11	28
Duval	9,400,951	94	58,450	93,535	9,401,147	282	16,576
Flagler	42,599	4	8	16	42,619	9	22
Nassau	390,316	17	50	102	390,456	64	167
Putnam	1,028,412	23	67	121	1,028,581	81	203
St. Johns	289,669	25	97	200	289,924	119	328
Florida	11,534,505	197	58,718	94,051	11,535,331	611	17,401
Bryan	30,297	99	310	466	30,834	482	745
Camden	119,527	2	6	12	119,546	8	21
Chatham	3,974,296	17,865	18,794	1,603	4,493,297	21,297	13,594
Effingham	85,243	17	117	150	85,303	39	95
Glynn	941,662	15	39	14,183	941,736	254	29,091
Liberty	125,219	6	16	32	125,250	8	48
Long	40,592	27	52	126	40,630	72	175
Mc Intosh	30,228	43	63	112	30,337	-157	145
Georgia	5,347,063	18,075	19,398	16,685	5,866,994	22,001	43,913
Brunswick	228,064	25	89	175	228,301	108	294
Columbus	621,071	9	28	53	621,145	34	140
New Hanover	1,813,149	49	176	343	1,813,566	219	582
Pender	123,145	1	10	40	123,189	11	53
North Carolina	2,785,428	85	305	613	2,786,201	373	1,070
Beaufort	1,324,545	34	93	177	1,324,738	110	272
Berkeley	367,786	-3	8	21	367,813	9	33
Charleston	3,439,852	192	47,236	65,055	3,440,477	47,412	60,434
Colleton	438,847	9	51	108	438,977	62	186
Dorchester	300,302	5	61	126	300,480	78	228
Georgetown	564,288	4	15	28	564,326	18	49
Hampton	198,303	2	7	13	198,316	9	20
Horry	1,253,802	47	167	332	1,254,235	206	605
Jasper	87,771	20	57	105	87,920	72	177
Williamsburg	380,604	10	25	38	380,722	26	47
South Carolina	8,356,100	321	47,720	66,004	8,358,004	48,000	62,050
South Atlantic	28,023,094	18,678	126,141	177,352	28,546,527	70,987	124,434

TABLE XI

Number of Jobs Created by OCS Development - 1984
South Atlantic Coastal Region

Industrial Sector	Base I	Scenario Minus Base A	Scenario Minus Base B	Scenario Minus Base D	Base II	Scenario Minus Base C	Scenario Minus Base E
Ag. and Food Process.	35491	0	0	2	35491	0	2
Forestry and Fisheries	311	0	0	0	311	0	0
Non Petrol. Mining	213	0	0	0	213	0	0
Petroleum Mining	4	243	243	571	4	243	571
Apparel and Textiles	24177	0	0	0	24177	0	0
Lumber and Wood Prod.	42842	0	0	0	42842	0	0
Chemical and Plastics	13367	1	1	2	13373	1	2
Petroleum Refining	1062	0	8	0	1612	0	0
Leather, Glass and Stone	6212	3	2	2	6220	1	2
Iron and Steel	4473	5	5	7	4474	5	7
Other Metals	5855	5	3	4	5890	2	4
Machinery and Misc. Mfg.	15064	32	33	87	15063	32	87
Transportation	34981	105	83	140	35018	82	189
Communications	15587	2	2	12	15584	3	11
Utility	4110	0	0	4	4110	0	4
Wholesale Trade	51907	194	130	261	51976	128	261
Fin., Ins., and Real Estate	62096	0	0	-3	62096	0	-3
Amusement and Service	41851	13	12	22	41859	12	21
Retail Stores	134904	466	310	627	135069	308	628
Medical and Ed. Inst.	52330	18	17	36	52344	17	36
Auto Dealers and Service	28910	87	59	120	28944	60	122
Construction	50162	1384	800	1572	50258	802	1579
Federal Civil. Govt.	39808	92	83	154	39854	82	155
State and Local Govt.	105830	228	193	426	105993	191	430
Armed Forces	34094	0	0	0	34094	0	0
Domestic Services	28417	25	21	48	28435	22	49
TOTAL	834059	2903	2004	4092	835303	1992	4157

TABLE XI (cont'd.)

Number of Jobs Created by OCS Development - 1988
South Atlantic Coastal Region

Industrial Sector	Base I	Scenario Minus Base A	Scenario Minus Base B	Scenario Minus Base D	Base II	Scenario Minus Base C	Scenario Minus Base E
Ag. and Food Process.	33634	0	0	4	33633	1	3
Forestry and Fisheries	187	0	0	0	187	0	0
Non Petrol. Mining	197	0	0	0	197	0	0
Petroleum Mining	5	309	395	881	5	378	881
Apparel and Textiles	25961	1	1	1	25962	0	0
Lumber and Wood Prod.	45082	0	0	2	45082	0	1
Chemical and Plastics	13856	0	2	10	13871	3	7
Petroleum Refining	1091	0	58	27	1640	19	10
Leather, Glass and Stone	6462	4	5	9	6471	5	7
Iron and Steel	5110	7	15	22	5111	12	21
Other Metals	5980	8	11	23	6015	10	25
Machinery and Misc. Mfg.	14972	43	47	185	14970	44	175
Transportation	35980	42	122	593	36029	122	583
Communications	16551	6	11	21	16544	8	2
Utility	4226	0	7	13	4226	4	11
Wholesale Trade	56464	83	63	483	56560	52	396
Fin., Ins., and Real Estate	70626	0	-1	-12	70628	-2	-27
Amusement and Service	45175	25	26	46	45189	22	27
Retail Stores	145582	195	141	1109	145805	125	962
Medical and Ed. Inst.	59679	37	47	88	59705	42	75
Auto Dealers and Service	30850	43	39	227	30898	34	203
Construction	53538	232	54	3796	53637	47	2040
Federal Civil. Govt.	41791	65	86	204	41845	84	216
State and Local Govt.	114554	213	261	596	114751	253	639
Armed Forces	33470	0	0	0	33470	0	0
Domestic Services	27849	22	27	62	27870	26	66
TOTAL	888872	1335	1419	8386	890301	1288	6322

TABLE XI (cont'd.)

Number of Jobs Created by OCS Development - 1992
South Atlantic Coastal Region

Industrial Sector	Base 1	Scenario Minus Base A	Scenario Minus Base B	Scenario Minus Base D	Base II	Scenario Minus Base C	Scenario Minus Base E
Ag. and Food Process.	31969	1	1	5	31969	1	1
Forestry and Fisheries	114	0	0	0	114	0	0
Non Petroleum Mining	182	0	0	0	182	0	0
Petroleum Mining	5	309	396	995	5	379	978
Apparel and Textiles	27798	0	0	0	27798	0	0
Lumber and Wood Prod.	47386	0	0	1	47387	0	1
Chemical and Plastics	14298	1	6	19	14322	4	15
Petroleum Refining	1105	0	124	101	1654	53	51
Leather, Glass and Stone	6695	4	6	15	6705	6	11
Iron and Steel	5730	8	17	34	5731	14	30
Other Metals	6120	8	12	25	6156	9	28
Machinery and Misc. Mfg.	15031	52	58	227	15027	49	214
Transportation	36844	35	174	458	36893	165	450
Communications	17620	7	16	30	17614	8	-8
Utility	4316	1	12	31	4317	6	23
Wholesale Trade	61247	73	120	229	61346	103	206
Fin., Ins., and Real Estate	79929	0	-2	-26	79935	-2	-59
Amusement and Service	48710	32	38	59	48731	27	6
Retail Sotres	157246	167	274	532	157463	234	469
Medical and Ed. Inst.	67717	50	66	148	67756	59	109
Auto Dealers and Service	32858	40	75	166	32910	66	158
Construction	56933	103	150	380	57029	139	395
Federal Civil. Govt.	43671	52	85	194	43725	77	196
State and Local Govt.	122927	158	243	508	123128	215	515
Armed Forces	32859	0	0	0	32859	0	0
Domestic Services	27161	15	23	48	27180	21	49
TOTAL	946471	1116	1893	4178	947940	1628	3833

TABLE XI (cont'd.)

Number of Jobs Created by OCS Development - 1996
South Atlantic Coastal Region

Industrial Sector	Base 1	Scenario Minus Base A	Scenario Minus Base B	Scenario Minus Base D	Base II	Scenario Minus Base C	Scenario Minus Base E
Ag. and Food Process.	30365	1	1	5	30365	1	-1
Forestry and Fisheries	68	0	0	0	68	0	0
Non Petrol. Mining	166	0		0	166	0	0
Petroleum Mining	6	309	396	996	6	379	979
Apparel and Textiles	29594	0	0	0	29594	0	0
Lumber and Wood Prod.	49619	1	1	1	49622	0	1
Chemical and Plastics	14645	1	8	26	14674	6	22
Petroleum Refining	1140	0	181	169	1689	83	90
Leather, Glass and Stone	6904	5	8	19	6916	7	13
Iron and Steel	6314	10	20	39	6317	15	33
Other Metals	6251	8	13	26	6286	10	39
Machinery and Misc. Mfg.	15126	56	64	243	15122	50	227
Transportation	37528	35	165	436	37574	152	421
Communications	18717	7	23	39	18715	12	-2
Utility	4368	0	19	45	4369	9	33
Wholesale Trade	66058	78	138	284	66160	113	245
Fin., Ins., and Real Estate	89708	1	-2	-34	89720	0	-83
Amusement and Service	52352	39	63	103	52385	45	23
Retail Stores	169385	173	306	646	169593	241	541
Medical and Ed. Inst.	76234	63	91	195	76290	80	137
Auto Dealers and Service	34805	41	91	212	34859	79	195
Construction	60204	105	163	332	60299	144	313
Fed. Civil Govt.	45358	51	88	172	45411	78	166
State and Local Govt.	131255	164	272	551	131461	230	527
Armed Services	32259	0	0	0	32259	0	0
Domestic Services	26329	14	23	48	26347	20	46
TOTAL	1004758	1160	2134	4552	1006267	1754	3956

TABLE XII

Value of Output Induced by OCS Development - Petroleum Refining

Year	County and State	Base I	A(Low)	B(Low)	D(High)	Base II	C(Low)	E (High)
1984	Florida	52008	2	2603	0	51982	1	-1
	Duval	52008	2	2603	0	51982	1	-1
	Georgia	149478	1	-5	2	647583	1	3
	Chatham	139745	0	-5	0	637898	0	0
	Glynn	0	0	0	0	0	0	0
	North Carolina	0	0	0	0	0	0	0
	South Carolina	33725	1	-1	8	33728	0	7
	Charleston	33725	1	-1	8	33728	0	7
	South Atlantic	235211	4	2597	10	733293	2	9
1988	Florida	66190	1	15607	10489	66122	-8	-5
	Duval	66190	1	15607	10489	66122	-8	-5
	Georgia	171603	3	-22	-6	669628	-7	3665
	Chatham	160977	0	-21	-11	659130	-11	0
	Glynn	0	0	0	0	0	0	3658
	North Carolina	0	0	0	0	C	0	0
	South Carolina	33787	0	6818	4	33794	6828	7
	Charleston	33787	0	6818	4	33794	6828	7
	South Atlantic	271580	5	22403	10487	769544	6812	3668
1992	Florida	81542	0	30750	27318	81435	-27	-26
	Duval	81542	0	30750	27318	81435	-27	-26
	Georgia	192172	6	-26	18	690149	-7	5860
	Chatham	180598	0	-24	-24	678751	-12	-11
	Glynn	0	0	0	0	0	0	5863
	North Carolina	0	0	0	0	0	0	0
	South Carolina	34042	0	21765	15464	34048	21788	15253
	Charleston	34042	0	21765	15464	34048	21788	15253
	South Atlantic	307756	6	52489	42764	805627	21754	21087
1996	Florida	97686	1	46935	46311	97548	-52	-52
	Duval	97686	1	46935	46311	97548	-52	-52
	Georgia	227589	8	-30	20	725525	-5	9331
	Chatham	214965	0	-29	-29	713117	-14	-14
	Glynn	0	0	0	0	0	0	9325
	North Carolina	0	0	0	0	0	0	0
	South Carolina	34217	0	37822	32934	34203	37862	31970
	Charleston	34217	0	37822	32934	34203	37862	31970
	South Atlantic	359492	9	84727	79225	857276	37805	41249

Table XIII

OCS Induced Changes in the Value of Output in Transportation

Year	State and County	Base I	Scenario - Base A	B	D	Base II	Scenario - Base C	E
1988	Florida	468,184	7	1,884	11,030	468,186	21	2,046
	Duval	438,085	6	1,881	11,035	438,082	19	2,047
	Georgia	156,597	1,760	1,679	2,387	158,620	3,443	13,693
	Chatham	149,398	1,752	1,674	169	151,415	3,412	6,279
	Glynn	4,013	1	1	2,214	4,015	-23	7,407
	North Carolina	100,051	2	4	9	100,055	5	11
	South Carolina	167,775	9	1,577	11,599	167,789	1,576	7,387
	Charleston	128,500	7	1,577	11,603	128,505	1,574	7,391
	South Atlantic Region	892,607	1,778	5,143	25,025	894,650	5,044	23,136
1992	Florida	541,873	13	2,960	12,401	541,885	30	1,546
	Duval	504,465	9	2,954	12,390	504,465	23	1,531
	Georgia	178,495	1,625	1,758	1,889	180,697	4,276	14,409
	Chatham	170,007	1,621	1,752	189	172,193	4,258	7,934
	Glynn	4,775	1	1	1,691	4,777	9	6,460
	North Carolina	114,168	3	8	16	114,183	8	21
	South Carolina	198,467	17	3,429	7,330	198,494	3,433	5,113
	Charleston	151,432	13	3,421	7,314	151,442	3,422	5,092
	South Atlantic Region	1,033,004	1,657	8,154	21,634	1,035,258	7,747	21,090
1996	Florida	621,983	13	3,163	12,579	622,007	37	1,565
	Duval	576,417	9	3,153	12,562	576,421	26	1,538
	Georgia	202,885	1,825	1,948	1,767	205,232	4,449	14,078
	Chatham	192,802	1,817	1,959	207	195,144	4,451	7,933
	Glynn	5,720	1	2	1,564	5,723	9	6,144
	North Carolina	130,466	4	13	23	130,491	14	36
	South Carolina	233,928	19	3,605	8,736	233,970	3,611	6,480
	Charleston	178,098	15	3,593	8,713	178,114	3,596	6,444
	South Atlantic Region	1,189,262	1,862	8,729	23,105	1,119,700	8,111	22,159

The value of refining output as a percent of the base value is significant for all counties involved in direct OCS development except Chatham where refinery investment is specified in Base II. The increase is most dramatic in the Charleston area where output climbs from $34 million to $72 million, an increase of 211%. These results should be interpreted with caution because of the lack of pipeline and water transportation being incorporated into the model, both of which are important transportation modes for petroleum products in the region.

Table XIII shows the change in the value of output and Table XIV shows the change in the number of jobs in transportation in the states and selected counties in the South Atlantic. The number of jobs created in transportation is a more significant variable than the value of output. Both tables were included to allow the reader to compare the relationship between the value of output and the number of jobs. The only time the percentage change over base levels is significant is in Georgia in Scenario E. Employment in transportation increases 50% in Glynn County in 1996.

No OCS induced changes occurred in the value of foreign competitive imports or foreign exports except the displaced foreign imports to the hypothetical refinery in Savannah in Base II.

Changes in population responds to changes in the number of jobs.

Table XIV

OCS Induced Changes in the Number of Jobs in Transportation

Year	State and County	Base I	Scenarios Minus Base A	B	D	Base II	Scenario Miunus Base C	E
1988	Florida	17,184	-1	44	241	17,184	0	47
	Duval	15,716	0	45	262	15,716	1	48
	Georgia	8,826	42	41	56	8,875	84	359
	Chatham	8,383	42	40	3	8,431	81	150
	Glynn	223	1	1	53	224	-1	208
	North Carolina	4,149	0	0	0	4,150	0	0
	South Carolina	5,820	1	38	277	5,821	37	176
	Charleston	4,304	0	38	277	4,304	38	177
	South Atlantic Region	35,980	42	122	593	36,029	122	583
1992	Florida	17,630	0	63	262	17,630	1	32
	Duval	16,077	0	63	262	16,077	0	32
	Georgia	8,938	35	38	40	8,986	91	309
	Chatham	8,483	34	37	3	8,530	91	169
	Glynn	231	0	0	36	231	0	138
	North Carolina	4,211	0	0	-1	4,211	0	0
	South Carolina	6,065	1	74	156	6,066	73	109
	Charleston	4,482	0	73	155	4,482	73	109
	South Atlantic Region	36,844	35	174	458	36,893	165	450
1996	Florida	17,949	0	60	238	17,950	0	28
	Duval	16,324	0	60	238	16,324	0	28
	Georgia	9,005	35	36	32	9,049	83	269
	Chatham	8,537	35	38	3	8,582	85	152
	Glynn	238	0	0	30	238	0	118
	North Carolina	4,277	0	0	0	4,278	0	0
	South Carolina	6,296	1	69	167	6,297	69	124
	Charleston	4,653	0	69	166	4,653	69	123
	South Atlantic Region	37,528	35	165	436	37,574	152	421

Tabla XV

Comparison of Harris Model Runs

Runs	Resource Estimates	Base Used for Comparison	Refinery-Location	Resource Location	Onshore Gas Pipeline and Processing Plant	Onshore Oil Pipeline Terminals	Surface Transportation of Oil-Products	Overland Pipeline Routes	Operation Base Locations	Central Office Location
Base I	0	-	0	-	0	0	0	0	0	0
Base II	0	-	S	-	0	0	Crude & Products	0	0	0
Base III	0	-	J	-	0	0	Crude & Products	0	0	0
A	Low	I	0	Random	0	(Offshore)	Crude	0	S	S
B	Low	I	0	Oil-South; Gas-North	C	F	Crude	0	S	S
C	Low	II	(S)	Oil-South; Gas-North	C	B	0	B ← S	S	S
D	High	I	0	Random	C,F	C,F	Crude	0	F,B,C	S
E	High	II	(S)	Random	C,B	S	0	0	F,B,C	S
GASC	High	II&III	(S) (J)	Random	C,B	C,B	0	B ← S ← C	U,G	S
NC	High	I	0	Random	C,F	C,F	Crude	0	F,B,W	S
GMAX	High	I	*B	All-Georgia	B,U	B	Products	B	U	B
FMAX	High	I	*F	All-Florida	2-F	F	Products	0	F	F
SCMAX	High	I	*C	All-South Caro.	C,G	C	Products	0	G	C
NCMAX	High	I	*W	All-North Caro.	2-W	W	Products	0	W	W

S - Savannah, Chatham County, Georgia
J - Jasper County, South Carolina
B - Brunswick, Glynn County, Georgia
F - Jacksonville, Duval County, Florida
C - Charleston, Charleston County, South Carolina
W - Wilmington, New Hanover County, North Carolina
U - Camden County, Georgia (Undeveloped area)
G - Georgetown, Georgetown County, South Carolina

( ) - Refineries in parenthesas are not OCS induced.
* - In order to consider a maximum economic impact situation, OCS activity - induced refineries were hypothesized for the impacted states in these scenarios. However, such refineries are considered highly unlikely.

CHAPTER IV

Additional Scenarios

Six additional scenarios and one additional base case were formulated after the discussion of the initial assumptions with representatives of the states involved in the proposed South Atlantic Sale 43. The formation of the additional runs benefited from the more detailed information provided by the state representatives on alternative locations that might be developed. An interest was expressed by some of the states in having a scenario which represented the maximum possible (although improbable) impact that might occur in their state. It was decided to create a maximum case scenario for each state.

The maximum case described in the scenarios represents the case in which all discoveries of oil and gas are located directly offshore one state. It was hypothesized that this would cause all onshore development to occur in the state adjacent to the discovery. For the maximum case BLM also included an assumption that a refinery would be induced as a result of the OCS development.

This chapter has a format similar to Chapter II. This is to allow the reader to compare this set of scenarios with the initial set of scenarios. Table XV contains a one page summary of the highlights of all scenarios to help facilitate this comparison. Table XVI summarizes the additional scenarios and is set up in a manner similar to Table II to allow the reader to compare specific components. Table XVII describes the probable nonconstruction employment for the additional scenarios and can be compared with Table III. A more detailed description of the additional scenarios and assumptions follow.

Economic Assumptions

All economic variables that were specified in the initial runs remain the same in this set of runs with the exception of the refinery specification. Assumptions that remain constant include assumptions about civilian unemployment rate, prices of oil and natural gas, material or labor constraints, deep water ports, OCS production replacing imports, and the nature of the leasing system.

The assumption that petroleum refineries would be induced in the maximum cases was included for the following reasons. Although industry representatives indicated that it was highly unlikely that a fully integrated refinery would be induced from petroleum discoveries in the South Atlantic there is still a small possibility that this might occur. A fully integrated refinery resulting from the sale would have a large impact and should be considered in any maximum impact analysis. It should be pointed out, however, that the maximum impact case in any of the South Atlantic states has a very small probability of actually occurring.

Employment shown in Table XVIII in the scenarios with refinery assumptions differs primarily through the treatment of refinery employment. Refinery employment was considered induced in all maximum cases. A base case (Base III) has a refinery in Jasper County, South Carolina. Refinery employment in the run using the base was not considered in OCS employment.

Resource Assumptions

All resource assumptions were based on U. S. Geological Survey's high resource estimates and are consistent with the values used in the initial set of scenarios. Appendix B and Chapter II contain a more detailed description of the estimates. A summary of the estimates is shown as part of Table XVI.

The only difference between scenarios in resource specifications exists in the hypothesized location of the resources. For the scenarios GASC and NC, the same randomly determined resource locations were used as in scenarios D and E. The methodology used in determining these resource locations is described in Chapter II.

Resources were located directly offshore each of the South Atlantic states in the maximum case. If this were to happen some efficiencies could be expected in the production of the mineral resources. It was assumed that the same number of wells and platforms would be necessary to develop the resource. Efficiencies were allowed in requirements for onshore support development using estimates obtained from industry. These are shown in Table XV and will be discussed in the next section.

Scenario Development and Comparisons

An additional base case (Base III) and six additional scenarios were developed. These will be described separately. Generalized assumptions that remain consistent between this and the initial set of scenarios include:

Table XVI. Comparison of Additional Base Case and Scenarios

Comparison Factors	Year	Base III	NC	GASC	FMAX	GMAX	SCMAX	NCMAX	Comments
OCS Resource Estimates Oil (Billion Barrels) Gas (Trillion Cubic Feet)		no develop- ment " "	1.009 6.810	1.009 6.810	1,009 6,810	1,009 6,810	1.009 6,810	1.009 6.810	1) All oil and gas production that is shown is sold. Oil and gas production continues until 2006, only the 20 years included in the model are shown.
Average daily production Oil	1982	no	8000						2) OCS oil replaces imports in the rest of the nation in NC, and OCS oil replaces imports to a hypothetical refinery in GSC, FMAX, GMAX, SCMAX, and NCMAX.
	1983	development	25000						
	1984	" "	41000						
	1985	" "	55000	All scenarios have the same production rates.					
	1986	" "	77000						
	1987	" "	99000						
	1988	" "	134000						3) Resources are randomly destributed as described in the inital scenarios in NC and GSCS. FMAX, GMAX, SCMAX, and NCMAX all assumed that oil and gas resources are located in a concentrated area off of the respective state.
	1989	" "	162000						
	1990	" "	170000						
	1991	" "	170000						
	1992	" "	170000						
	1993	" "	170000						
	1994	" "	170000						
	1995	" "	170000						
	1996	" "	170000						
Gas	1986	no	701						
	1987	development	726						
	1988	" "	726	All scenarios have the same production rates.					
	1989	" "	1359						
	1990	" · "	1397						
	1991	" "	1397						
	1992	" "	1397						
	1993	" "	1397						

Table XV1 (continued)

Comparison Factors	Yaar	Base 111	NC	GASC	FMAX	GMAX	SCMAX	NCMAX	Comments
	1994	no	1397						
	1995	development	1397						
	1996	" "	1397						
Oparations Base Location	1977	no davelopmant	GL*	GL**	D***	C***	(GE)***	NH***	1)Location abbreviations: NH-Naw Hanovar, N.C.; D-Duval, Fla.; GL-Glynn, Ga.; C-Camdan, Ga.; S-Chatham, Ga.; SC-Charleston, S.C.; GE-Georgatown, S.C., Jaspar, S.C.
	1978	" "	NH*	SC*					2)Onshore operations basa's invastment and employment wera based on astimates of tha Offshora Operators Committae. In tha max casas it was assumed that investmant occurad in two separate phasas. Tha yaar that tha sacond phase of invastment occurs is indicatad by the parenthasis. Total Costs / Employment * 1,027,000 / 103 ** 2,000,000 / 125 ***2,800,000 / 136
	1979		D*	(GL)	(D)	(C)	(GE)	(NH)	3)Oparation basa locations ara assumed to sarve as place of employment for all offshora parsonnal.

Table XVI continued

Comparison Factors	Year	Base III	NC	GASC	FMAX	GMAX	SCMAX	NCMAC
Exploration								
#Drilling vessels/ #wells drilled	1977	no	4/12					
	1978	development	10/30					
	1979		10/30					
	1980		10/30					
	1981		7/21					
	1982		5/15	All scenarios have the same amount of exploration activity.				
	1983		5/15					
	1984		5/15					
	1985		3/15					
	1986		3/9					
	1987		3/9					
	1988		3/9					
	1989		1/3					
	1990		1/3					
	1991		1/2					
	1992		1/2					

Comments:

1)Assumptions used for all scenarios
  a)Cost-$2,000,000/well
  b)Drilling rate - 3 wells/ year/drilling vessel
  c)Employment - 113/drilling vessel

2)Investment and employment is assigned to locations as follows:
  a)NC-Evenly divided between the three operations base
  b)GASC-divided 1/3 - Charleston, 2/3 Camden
  c)All MAX scenarios-all assigned to the respective operations base.

Comparison Factors	Year	Base III	NC NH	NC D	NC GL	GASC C	GASC SC	FMAX D	GMAX C	SCMAX GE	NCMAC NH
Development:Location #Platforms	1980	no	1	0	1	1	1	2	2	2	2
	1981	development	1	1	0	1	1	2	2	2	2
	1982		1	0	2	2	1	3	3	3	3
	1983		1	2	0	2	1	3	3	3	3
	1984		1	0	2	2	1	3	3	3	3
	1985		0	0	3	3	0	3	3	3	3
	1986		0	3	0	3	0	3	3	3	3
	1987		1	1	1	2	1	3	3	3	3
	1988		2	0	1	1	2	3	3	3	3

Comments:

1)Assumptions common to all scenarios:
  a)no more than 2 drilling rigs on each platform, no more than 20 wells per platform
  b)each rig can drill 5 wells/ year
  c)development well costs $500,000/well
  d)drilling rigs employ 65/ rig

Table XVI continued

Comparison Factors	Year	Base III	NC NH	NC D	NC GL	GASC C	GASC SC	FMAX D	GMAX C	SCMAX GE	NCMAX NH
Development:Location # Wells	1981	no	5	0	5	5	5	10	10	10	10
	1982	development	12	6	7	13	12	25	25	25	25
	1983		22	7	21	28	22	50	50	50	50
	1984		27	16	27	43	27	70	70	70	70
	1985		24	11	40	51	24	75	75	75	75
	1986		10	0	50	50	10	60	60	60	60
	1987		0	20	40	60	0	60	60	60	60
	1988		20	20	20	40	20	60	60	60	60
	1989		17	0	23	23	17	40	40	40	40
	1990		13	0	12	12	13	25	25	25	25
	1991		9	0	11	11	9	20	20	20	20
	1992		2	0	3	3	2	5	5	5	5
	1993		2	1	2	3	2	5	5	5	5
	1994		2	1	2	3	2	5	5	5	5
	1995		1	0	4	4	1	5	5	5	5
	1996		1	2	2	4	1	5	5	5	5

Comments:

  e)after initial drilling is complete 2 rigs remain active doing service wells and workovers
  f)platforms cost $25,000,000 platform
  g)permanent platforms employ 22 persons.

Comparison Factors	BASE III	NC	GASC	FMAX	GMAX	SCMAX	NCMAX	Comments
Terminals & Processing Facilities Gas Processing	none	700mmcf/ day processing plant built in Duval, Fla. in 1985; and in Charleston, S.C. in 1987	700mmcf/ day processing plant built in Glynn, Ga.; in 1985; and in Charleston, S.C. in 1988	Two 700mmcf/ day processing plants built in Duval, Fla. 1985 and 1988	700mmcf/ day processing plant built in Glynn, Ga. 1985; and in Camden, Ga. in 1988	700mmcf/ day processing plant built in Charleston, S.C. in 1985; and in Georgetown, S.C. in 1988	Two 700mmcf/ day processing plants built in New Hanover, N.C. in 1985 and 1988	1)Cost of 700mmcf/day gas processing plant $60,000,000 and employs 30 persons

Table XVI continued

Comparison Factors	Base III	NC	GASC	FMAX	GMAX	SCMAX	NCMAX	Comments
Oil Terminals	none	Crude terminal connected with a port - Duval, Fla. 1985 and Charleston, S.C. 1988	Terminal and pumping station 1985-Glynn, Ga., and Charleston, S.C., 1988	Terminal and pumping station 1985-Duval, Fla.	Crude terminal and pumping station and new products handling terminal, Glynn, 1985	Terminal and pumping station 1985-Charleston, S.C.	Terminal and pumping station 1985-New Hanover, N.C.	1)Terminal and pumping station costs $2,400,000, employment 17 2)Terminal connected with a port facility costs $4,000,000, employment 13 3)Crude terminal and products terminal costs $11,400,000, employment 42 (Additional costs necessary because facility is not connected with the refinery
Refineries:Location and year operations begin	J 1982	no specified refineries	GASC is run against Base II (refinery in Chatham, Ga.) and Base III (refinery in Jasper S.C.)	D 1986	GL 1986	SC 1986	NH 1986	1)Refinery Investment totals $400,000,000; employment is 550 persons; capacity - 200,000 barrels/day 2)Output in Petroleum refining is constrained in Chatham, Co, Ga. in same manner as initial scenarios
Miscellaneous Central Office: Location/Employment	none	S 1977-39 1978-36 1979-96-42	GL 1977-30 1978-36 1979-96-42	D 1977-30 1978-36 1979-96-42	GL 1977-30 1978-36 1979-96-42	SC 1977-30 1978-36 1979-96-42	NC 1977-30 1978-36 1979-96-42	1)Pollution containment and cleanup equipment is located at operation bases. Refineries are assumed to have their own pollution equipment which is included in the investment costs.

Table XVI continued

Comparison Factors	Base III	NC	GASC	FMAX	GMAX	SCMAX	NCMAX	Comments
Pollution Containment and Cleanup Equip. Investment - Location:Year/ Amount	none	GL 1977/$300,000 1981/$470,000 NH 1978/$300,000 1981/$470,000 D 1982/$470,000	C 1977/$300,000 1981.$470,000 GE 1978/$300,000 1981/$470,000	D 1977/$300,000 1981/$470,000 1981/$470,000	C 1977/$300,000 1981/$470,000 1981/$470,000	GE 1977/$300,000 1981/$470,000 1981/$470,000	NH 1977/$300,000 1981/$470,000 1981/$470,000	1)Refineries have their own pollution containment and cleanup equipment.
Transportation of OCS Products Oil:Destination	none	"rest of nation"	Refinery at Chatham or Jasper	Refinery at Duval, Fla.	Refinery at Glynn, Ga.	Refinery at Charleston, S.C.	Refinery at New Hanover, N.C.	1)Investment per mile of major marine pipeline was estimated at $1,000,000/mile, investment per mile of land pipeline was based on estimate obtained by the state of Georgia: Total costs for 78 miles of 36" pipeline with 800 lbs. of pressure is $56,000,000. 2)Mileage for overland pipeline obtained by using railroad/highway or other rights-of-ways.
Transportation mode	none	Initial tankering 1985 90 miles of pipeline built to Duval Co., Fla.; 1988 65 miles pipeline built to Charleston Co. S.C., all oil is then tankered from these ports to the rest of nation	Initial tankering of oil 1985, 80 miles of marine pipeline to Glynn, Ga., overland pipeline miles to refinery in Georgia: Glynn 28 McIntosh 18 Liberty 14 Brynn 10 Chatham 18 In 1988-75 mile marine pipeline to Charleston, overland miles to refinery S.C. Charleston 15 Jasper 38	Initial tankering of oil 1985, 75 miles of marine pipeline to Duval, Fla., products are shipped out of area.	Initial tankering of oil in 1985, 80 miles of marine pipeline and 40 miles of land pipeline (20 miles one way) are built to refinery in Glynn, Ga.; products are shipped out of area.	Initial tankering of oil 70 miles of marine pipeline to refinery in Charleston in 1985; products are shipped out of area.	Initial tankering of oil, 108 miles of marine pipeline to refinery in New Hanover Co., N.C.; products shipped out of the area.	

Table XVI continued

Comparison Factors	Base III	NC	GASC	FMAX	GMAX	SCMAX	NCMAX	Comments
Gas:	none	80 miles of marine natural gas pipeline to Duval, Fla. in 1986 and 68 miles of marine natural gas pipeline to Charleston, S.C. in 1989	76 miles of marine natural gas pipeline to Glynn, Ga. in 1986, and 68 miles of marine natural gas pipeline to Charleston, S.C. in 1989	75 miles of marine natural gas pipeline to Duval, Fla. in 1986; additional 5 land miles built in 1989 to second gas processing plant	80 miles of marine natural gas pipeline to Glynn, Ga.; in 1986; 80 miles marine natural gas pipeline to Camden, Ga., in 1989	70 miles marine natural gas pipeline to Charleston, S.C. in 1986; 70 mile marine natural gas pipeline to Georgetown, S.C. in 1989	108 miles of marine natural gas pipeline to New Hanover in 1986; additional 5 land miles built in 1989 for second gas processing plant	1) Investment per mile of major marine pipeline was estimated at $1,000,000;mile; investment per mile of land pipeline was estimated at $300,000. 2) It was assumed that an additional 5 mile of land pipeline would be necessary to connect the plant with existing distribution systems. In the case of Camden Co., Ga. this was increased to 20 miles

Table XVII. Timing of Total Direct Nonconstruction Employment - Scenarios FMAX, SCMAX, NCMAX Sale 43

Year	Total Offshore Employment	Office	Operations Base	Gas Processing Plant	Oil Pipeline Terminal	Refinery	Total
1976							
1977	452	30	68				550
1978	1130	36	102				1268
1979	1130	42	136				1308
1980	1130	42	136				1308
1981	1075	42	136				1253
1982	934	42	136				1112
1983	1303	42	136				1481
1984	1607	42	136				1785
1985	1716	42	136		17	550	2461
1986	1405	42	136	30	17	550	2180
1987	1471	42	136	30	17	550	2246
1988	1573	42	136	30	17	550	2348
1989	1095	42	136	60	17	550	1900
1990	944	42	136	60	17	550	1749
1991	923	42	136	60	17	550	1728
1992	793	42	136	60	17	550	1598
1993	680	42	136	60	17	550	1485
1994	680	42	136	60	17	550	1485
1995	680	42	136	60	17	550	1485
1996*	680	42	136	60	17	550	1485

* Employment is only shown for the 20 years modeled.

Table XVII. Timing of Total Direct Nonconstruction Employment - Scenario GMAX - Sale 43

Year	Total Offshore Employment	Office	Operations Base	Gas Processing Plant	Oil Pipeline Terminal	Refinery	Total
1976							
1977	452	30	68				550
1978	1130	36	102				1268
1979	1130	42	136				1308
1980	1130	42	136				1308
1981	1075	42	136				1253
1982	934	42	136				1112
1983	1303	42	136				1481
1984	1607	42	136				1785
1985	1716	42	136		42	550	2486
1986	1405	42	136	30	42	550	2208
1987	1471	42	136	30	42	550	2271
1988	1573	42	136	30	42	550	2373
1989	1095	42	136	60	42	550	1925
1990	944	42	136	60	42	550	1774
1991	923	42	136	60	42	550	1753
1992	793	42	136	60	42	550	1623
1993	680	42	136	60	42	550	1510
1994	680	42	136	60	42	550	1510
1995	680	42	136	60	42	550	1510
1996*	680	42	136	60	42	550	1510

* Employment is only shown for the 20 years modeled.

Table XVII. Timing of Total Direct Nonconstruction Employment - Scenario NC - Sale 43

Year	Total Offshore Employment	Office	Operations Base	Gas Processing Plant	Oil Pipeline Terminals	Total
1976						
1977	452	30	103			585
1978	1130	36	206			1372
1979	1130	42	309			1481
1980	1130	42	309			1481
1981	1075	42	309			1426
1982	934	42	309			1285
1983	1303	42	309			1654
1984	1607	42	309			1958
1985	1716	42	309		13	2080
1986	1405	42	309	30	13	1799
1987	1471	42	309	30	13	1865
1988	1537	42	309	30	26	1944
1989	1095	42	309	60	26	1532
1990	944	42	309	60	26	1381
1991	923	42	309	60	26	1360
1992	793	42	309	60	26	1230
1993	680	42	309	60	26	1057
1994	680	42	309	60	26	1057
1995	680	42	309	60	26	1057
1996*	680	42	309	60	26	1057

* Employment is only shown for the 20 years modeled.

Table XVII. Timing of Total Direct Nonconstruction Employment - Scenario GASC - Sale 43

Year	Total Offshore Employment	Office	Operations Base	Gas Processing Plant	Oil Pipeline Terminal	Total	Refinery (Chatham or Jasper)**
1976							
1977	452	30	103			585	
1978	1130	36	206			1372	
1979	1130	42	228			1400	
1980	1130	42	228			1400	
1981	1075	42	228			1345	
1982	934	42	228			1204	550
1983	1303	42	228			1573	550
1984	1607	42	228			1877	550
1985	1716	42	228		13	1999	550
1986	1405	42	228	30	13	1718	550
1987	1471	42	228	30	13	1784	550
1988	1537	42	228	30	26	1863	550
1989	1095	42	228	60	26	1451	550
1990	944	42	228	60	26	1302	550
1991	923	42	228	60	26	1279	550
1992	793	42	228	60	26	1149	550
1993	680	42	228	60	26	1036	550
1994	680	42	228	60	26	1036	550
1995	680	42	228	60	26	1036	550
1996*	680	42	228	60	26	1036	550

* Employment is only shown for the 20 years modeled.
** Refinery employment is not considered to be induced.

Table XVIII
Summary of Sale Induced Civilian Employment by States

State & Year	GASC-I	NC-I	SCMAX-I	FMAX-I	NCMAX-I	GMAX-I	GASC Minus Base II	Gasc Minus Base III
North Carolina								
1980	31	771	28	1	2012	4	12	31
1988	65	1116	71	1	6221	31	54	67
1996	64	708	60	20	3590	43	48	64
South Carolina								
1980	707	91	1650	20	90	27	636	703
1988	4728	2039	5183	13	221	131	4677	4278
1996	1438	689	4193	68	209	156	1392	1411
Georgia								
1980	2647	889	70	4	49	1544	1180	2649
1988	3983	1509	180	10	140	5844	2657	3971
1996	2853	1011	168	38	136	3338	1602	2771
Florida								
1980	55	910	46	2499	32	12	33	63
1988	110	2047	124	7079	101	68	110	118
1996	119	1857	126	5866	116	90	126	127

1) All offshore employment and investment is assigned to the county that contains the operations base. When more than one operations base exists, assignments are made to the nearest base.

2) Investment costs do not include the costs of land.

This scenario also included better estimates of overland pipeline mileage and costs provided by the State of Georgia.

Base III includes a non OCS induced 200,000 barrel/day refinery in Jasper County, South Carolina. In Base II a refinery was located in Chatham County, Georgia. At the time BLM formulated this assumption, it was considered that the likelihood of a refinery locating on either side of the Savannah River was equal. The Georgia side was determined as the site by a coin toss. Both the states of Georgia and South Carolina expressed an interest in seeing the differences predicted by the model when the refinery was located in South Carolina. Scenario GASC was developed with oil being transported to a refinery in the Savannah area. The scenario was then compared to both Base II and Base III.

Inputs used for the refinery in Base III remain the same as those used in Base II. Basically, the refinery modeled represents a 200,000 barrel/day refinery, costing $400 million and employing 550 persons.

Scenario GASC was developed to model the high resource case where oil is being transported by pipeline overland to a refinery in the Savannah area. Oil and gas resources are assumed to be randomly distributed. Some development occurs in Camden County, Georgia, a relatively undeveloped county. The county has an old Army facility with some already developed harbor facilities. It was felt that the inclusion of a less developed county would provide a contrast to the intial scenarios. Specific assumptions on scheduling and investment are found in Table XVI and employment assumptions are found in Table XVII. A summary of the basic components follow:

1) An operations base is established in Camden County, Georgia, in 1977. With the continuation of activity, it expands in 1979. Total investment costs $2,000,000 and employment is 125. This operations base services all of the tracts in the southern portion. Tracts in the northern portion are serviced by an operations base established in Charleston in 1978. Investment costs are $1,027,000 and employment is 103. Both bases stay in full operation during the years modeled.

Investment in pollution containment and pickup equipment occurs at the operations base and is determined by the scheduling of exploration and development phases. Investment costs are shown in Table XVI.

2) Initial oil production is stored on the platforms, gathered and tankered to the refinery in Savannah. Eighty miles of marine pipeline are built to Glynn County in 1985, and 75 miles of marine pipeline are built to Charleston in 1980. Pipeline is laid overland to a refinery in the Savannah area in either Jasper County, South Carolina or Chatham County, Georgia. Pipeline mileages used to estimate costs follow:

Georgia
Glynn County 28
McIntosh County 18
Liberty County 14
Bryan County 10
Chatham County 18
South Carolina
Charleston County 15
Jasper County 38

Costs were based on an estimated cost of $52 million for 78 miles of 36″ pipeline with 800 lbs. of pressure built over coastal terrain. Mileage used in the model includes an extra 10 miles for right-of-way considerations.

A terminal and pumping station is built in Glynn County, in 1985, and in Charleston County in 1988. Costs for the facility are $2,400,000 and employment is 17.

3) A 75 mile natural gas pipeline is built to Glynn County, Georgia in 1986 to a 700 mmcf/day processing plant. In 1989, 68 miles of natural gas pipeline are built to a 700 mmcf/day processing plant in Charleston, South Carolina. Five onshore miles of pipeline are necessary to connect the plants with existing distribution systems. The gas processing plant costs $60,000,000 and employs 30.

4) Central office staffs of 42 persons are assumed to be located in Glynn County, Georgia. Existing office space is assumed to be used.

Scenario NC is used to consider the possibility that development occurs onshore in North Carolina. Given a weighted random distribution of the resource this is unlikely because of the greater distance involved in reaching the North Carolina shoreline (relative distance; 70 miles to South Carolina versus 105 miles to North Carolina).

Scenario NC locates an operations base in New Hanover County, North Carolina to consider this option. A summmary of the scenarios' basic components follows:

1) Operations bases are built in Glynn County, Georgia, in 1977; New Hanover County, North Carolina in 1978, and Duval County, Florida, in 1979. Each base costs $1,027,000 and employs 103 persons.

Pollution containment and pickup equipment is located at the operations bases. Timing of investment is shown in Table B.

2) Initial oil production is stored on the platforms, gathered and tankered out of the area. After the completion of the oil pipeline (90 miles to Duval in 1985 and 65 miles to Charlestion in 1988) oil is conveyed to onshore terminals via these pipelines. Terminal facilities cost $4,000,000 and employs 13. All oil is tankered to areas outside the South Atlantic.

3) Two major marine natural gas pipelines, 82 miles to Duval County, Florida, and 70 miles to Charleston County, South Carolina are constructed to two 700 mmcf/day gas processing plants in 1986 and 1989 respectively. Investment costs for the gas processing plants are $60,000,000 per plant and employment is 30 persons.

4) A central office staff located in Savannah, Georgia employs 42 persons. Rented office space is assumed to be used.

Scenario FMAX describes the maximum development that might result in the State of Florida. It assumes that all resources are located off of the coast of Florida. Specific assumptions follows:

1) An operations base is built in Duval County, Florida in 1977. With continuous OCS development it is expanded in 1979. Total investment in the base is $2,800,000 and employment is 136 people.

Pollution containment and pickup equipment investment follow development and occur in 1977, 1980, and 1981. A complete summary is contained in Table XVI.

It should be noted that all offshore investment and employment is assigned to Duval County, Florida. A complete summary is contained in Tables XVI and XVII.

2) Oil is initially gathered on the platforms and tankered to the rest of the nation. In 1985 a 75 mile marine oil pipeline is constructed to a refinery in Duval County, Florida. Finished products are tankered to demand centers.

3) A 75 mile natural gas pipeline is constructed to Duval County in 1986. Two 700 mmcf/day natural gas processing plants are built in Duval in 1985 and 1988. Processed gas is distributed through existing distribution systems.

4) A petroleum refinery is built in Duval County, Florida in 1985, employment is estimated at 550 persons and cost at $400,000,000. It is assumed that OCS production will serve as feed stock throughout the time frame of the model. Refined products are assumed to be tankered to demand centers.

5) A central office is located in Jacksonville, Florida and employs 42 persons. Rented office space is used.

Scenario GMAX is similar to FMAX in the assumptions on resource location. Resources are located off of the coast of Georgia. Onshore development is distributed between Camden and Glynn counties. Specific assumptions follow:

1) An operations base is constructed at Camden County, Georgia, in 1977 and expanded in 1979. Use is made of existing harbor facilities at King's Bay. Investment costs $2,000,000 and employment at the base is 136 persons. In addition all offshore employment and investment is assigned to Camden County.

Pollution containment and pickup equipment are located at the operations base. A detailed summary of investment is found in Table XVI.

2) All oil is initially gathered, stored, and tankered from the individual platforms. An 80 mile marine pipeline and 20 mile land pipeline is constructed to a refinery in Glynn County, Georgia in 1985. Twenty miles of product line are constructed from the refinery to the harbor. A crude and product terminal connected with the port costs $11,400,000 and employs 42 persons. Finished products are then tankered to demand centers.

3) An 80 mile natural gas pipeline is built to Glynn County (1986) and Camden County (1989) connecting with 700 mmcf/day gas processing plants. An additional 5 miles in Glynn and 20 miles in Camden are assumed to be necessary to connect with existing distribution systems. Investment in a gas processing plant is $60,000,000 and employment is 30.

4) An OCS induced petroleum refinery is built in 1985 in Glynn County. Employment is estimated at 550 jobs and investment at $400,000,000. The refinery is not located at the harbor requiring

additional pipeline and product storage investments.

5) The central office staff estimated at 42 persons is located in Glynn County. Office space is rented.

Scenario SCMAX locates all development in South Carolina. An operations base is established at Georgetown, and development is divided between Georgetown and Charleston. A discussion of the scenarios' components follows:

1) In 1977 an operations base is established in Georgetown County, South Carolina. It is expanded in 1979. Total investment is $2,280,000 and employment is 136 persons. All offshore investment and employment is assigned to Georgetown.

Pollution containment and pickup equipment is located in Georgetown, investment scheduling and costs are shown in Table XVI.

2) Oil is initially gathered and stored on individual platforms before being tankered outside the area. A 70 mile oil pipeline is built to a refinery in Charleston in 1985. Refined products are tankered or trucked to demand centers.

3) Natural gas pipelines are built to Charleston (1986) and Georgetown (1989). Gas processing plants with 700 mmcf/day capacity counties cost $60,000,000 and employ 30 people. An additional 5 miles of pipeline for each processing plant was assumed to be necessary to connect with existing distribution systems.

4) A refinery built in Charleston in 1985 is run entirely on OCS feedstock during the time frame of this model. Investment costs are $400,000,000 and employment is 550.

5) The centered office staff of 42 persons is located in Charleston. Existing office space is utilized.

Scenario NCMAX is the maximum development case for North Carolina. In this scenario all onshore development occurs in New Hanover County, in the area of Wilmington. A description of the scenario follows:

1) In 1977, an operations base is established in New Hanover County, North Carolina. The base is expanded in 1979 and maintained throughout the life of the model with employment at 136. Total investment in the operations base is $2,800,000. All offshore investment and employment is assigned to New Hanover County. A complete summary of these inputs is found in Tables XVI and XVII.

Pollution containment and pickup equipment is located at the base in New Hanover. Investment costs are summarized in Table XVI.

2) Oil is initially gathered, stored, and tankered from individual platforms to refineries outside the area. A 108 mile marine oil pipeline is constructed to a refinery in the Wilmington area. Refined products are trucked or tankered to demand centers.

3) A natural gas pipeline is laid to a 700 mmcf/day natural gas processing plant in New Hanover in 1986. A second serviced plant comes on stream in 1988. Investment for the individual plants is $60,000,000 and employment is 136. Processed gas goes into existing distribution systems.

4) A 200,000 barrel/day refinery costing $400,000,000 and employing 550 is constructed in New Hanover County in 1985. The refinery uses OCS crude as feedstock throughout the time frame of the model. Finished products are moved by ship or truck to demand centers.

5) A central office staff of 42 is employed in Wilmington. It was assumed that existing office space was available and would be utilized.

A. Impact on Employment

In comparing the additional scenarios with the original five (A, B, C, D and E) it is easy to see that the results tend to have a wider range than the original scenarios. The averages of the additional scenarios are also higher than the averages for A, B, C, D and E. Common sense would also tend to predict these same sort of results.

Each of the additional scenarios postulated a consideration of oil findings in order to examine the possible extreme cases of concentrated economic impact. In addition each scenario was formulated with an assumption of high oil and gas reserves. The combination of these assumptions tends to produce high economic impacts in the states nearest the oil and gas concentrations. Negative numbers indicate migrations of employees to areas of higher job opportunity. For a summary of scenario impact on employment see Table XIX.

The easiest method of comparing the additional scenarios with the original set is to compare Table XX (Summary of Civilian Employment, Range and Average from Eight Additional Scenarios) with Tables E-7, 8 and 9 (Summary of Civilian Employment, Range and Average from Five

Table XIX
Summary of Sale Induced Civilian Employment (South Atlantic Region)

(Minus Base I)

Year	GASC-1	NC-1	SCMAX-I	FMAX-1	NCMAX-1	GMAX-1	GASC Minus Base II	GASC Minus Base III	Average
1980	3440	2662	1793	2524	2183	1586	1861	3446	2437
1984	3943	3813	4097	5028	5409	3769	2822	3964	4106
1988	8886	6711	5559	7103	6682	6075	7497	8434	7118
1992	4237	4002	4338	5821	3961	4337	2929	4187	4227
1994	4475	4265	4557	5993	4051	3627	3168	4376	4313

Note: All scenarios are based on a high resource estimate rounded to the nearest unit.

Table XX

Summary of Civilian Employment - Range and Average From Eight Additional Scenarios

	1980			YEAR 1988			1996		
	Low	High	Average (Rounded)	Low	High	Average (Rounded)	Low	High	Average (Rounded)
North Carolina									
Brunswick	1	2	2	1	5	4	4	7	6
Columbus	1	6	4	0	11	7	2	12	8
New Hanover	-1	2003	353	0	6199	934	13	3568	557
Pender	0	4	2	0	10	7	1	8	4
South Carolina									
Beaufort	1	6	4	-2	5	4	4	7	6
Berkeley	0	7	4	0	16	11	5	13	8
Charleston	18	136	61	20	2671	1447	40	2280	644
Colleton	0	3	2	-1	6	4	2	7	5
Dorchester	0	7	4	0	17	12	5	17	12
Georgetown	0	1472	403	-1	3682	796	1	1841	489
Hampton	0	0	0	0	0	0	1	2	1
Horry	0	15	0	-2	34	23	3	30	19
Jasper	0	2	1	0	1085	353	-1	12	6
Williamsburg	0	5	3	-2	12	7	1	9	6
Georgia									
Bryan	0	1	1	1	17	8	5	16	10
Camden	0	1461	584	0	3699	1175	1	1705	675
Chatham	3	1478	397	9	1405	417	17	1306	383
Effingham	0	12	3	-1	14	9	3	13	8
Glynn	0	774	141	1	2073	676	3	1550	397
Liberty	1	12	5	1	17	8	3	20	8
Long	0	1	1	0	3	2	4	8	6
McIntosh	0	1	0	0	9	4	-3	6	4
Florida									
Baker	0	4	2	0	8	5	1	7	5
Clay	-2	8	3	-1	18	12	0	13	7
Duval	12	2501	443	37	7077	1175	44	5845	1001
Flager	0	1	1	0	2	1	1	2	1
Nassau	0	1	1	2	6	5	11	21	16
Putnam	-1	8	4	0	22	13	6	23	16
St. Johns	0	4	3	1	10	8	4	10	8

Scenarios) in Chapter III. The main points of difference other than a wider range and a higher average lie in those counties which have been specified as OCS operation bases and refinery locations. Each scenario describes the location of an operation base, or bases, along with a refinery (except base scenario No. I which does not hypothesize a refinery). The summary of scenarios displays a high employment peak in those counties which are identified as operations bases or refinery locations. This could represent a short-term significant impact on those local communities if the present population is low and the local social infrastructure (housing, schools, etc.) is insufficient or absent.

However, in examining these impacts, it should be remembered that the scenarios identify all offshore employment as occurring in the operations base county along with all initial employment impacts. These assumptions combine to create a larger impact in the computer model than would take place in reality. The most important cautionary note to keep in mind while examining these results is that the assumptions of the additional scenarios involve extreme concentrations of oil discovery which are highly improbable in reality.

Table XXI examined the maximum impact on metropolitan areas in the South Atlantic region. In no case is the impact higher than two percent of the estimated future employment for 1990.

LIST OF ADDITIONAL SCENARIOS AND AREAS OF PRIMARY IMPACT

Scenarios

States of Primary Impact

NC1-I North Carolina
NCMAX-I North Carolina
SCMAX-I South Carolina
GMAX-I Georgia
FMAX-I Florida
GASC-I Georgia & South Carolina
GASC-II Georgia & South Carolina
GASC-III Georgia & South Carolina

All six scenarios were run using Base I assumptions (see Discussions of Base I, II and III Assumptions). In addition, the GASC scenario was run using Base II and then Base III assumptions.

These scenarios (and the base assumptions) were developed in cooperation with the South Atlantic States after consultation with state representatives. The rationale for developing the additional scenarios was to consider a wider set of possible futures.

The following tables include estimates of changes in earnings, per capita income, residential construction, private investment, and population for each scenario. These changes are calculated by subtracting the appropriate base.

B. Impact on Income

The main reason for creating the additional scenarios was to examine possible extreme impacts on individual states and areas. These scenarios and their resulting rungs were requested and in part designed by representatives from the South Atlantic state governments. Accordingly, summary tables of changes in earnings, per capita income, residential construction and private investment were constructed for each scenario (Tables XXII to XXX) in order to display the possible impacts of each scenario.

The major increases in earnings and per capita income are hypothesized to occur (depending on the scenario) in Duval County, Fla., Chatham County, Ga., Glynn County, Ga., Camden County, Ga., New Hanover County, N.C., Charleston County, N.C. and/or Georgetown, S.C. These projected increases occur in the counties where the operations bases or refineries are proposed to locate in each scenario. In each case, as in the original five scenarios, the effects are largely confined to single counties within the coastal counties. This may be explained by the lack of interties in commerce between coastal counties. The multiplier effects can be seen in the national totals but not the coastal sections of each state.

C. Impact on Residential Construction

These impacts parallel the employment and income impacts and demonstrate that additional land is needed for residential construction. Of course, the actual impacts will probably be of less magnitude because offshore workers may not live in the location of the operations base but instead use the mobility of their job situation (seven days on-seven days off) to locate in other counties or even other states.

D. Impact on Private Investment

Private investment in the model closely parallels the employment and incomes impacts and responds in a boom-bust manner which is very similar to reality. Due to the extreme concentrations of OCS activity that are assumed in each

Table XXI

Comparison of Future Estimated Employment Impacts

SMSA 1/	Total Employment 5/	Minimum Impact	Maximum Impact	Maximum Impact Percent
Jacksonville, Fla.	323,600	39 3/	6408 2/	1.9%
Savannah, Ga.	84,600	9 3/	1344 3/	1.5%
Charleston, S.C.	135,500	28 4/	1717 4/	1.3%

1/ Standard Metropolitan Statistical Area.
2/ Duval Co., Fla.
3/ Chatham Co., Ga.
4/ Charleston, S.C.
5/ USDC Bureau of Economic Analysis and USDA Economic Research Service; 1974. 1972 OBEAS Projections; Economic Activity in the U.S., Volume 2, BEA Economic Areas for the U.S. Water Resources Council U.S.G.P.O., Wash. D.C. April 1974

Table XXII
Scenario NC1-I - SUMMARY OF ECONOMIC IMPACTS
Earnings Impact Estimates ($1,000) in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	13	20	38	30	36
Clay	29	54	103	174	57
Duval	12,148	16,174	31,076	27,174	30,505
Flagler	6	8	15	12	14
Nassau	10	17	36	68	104
Putnam	51	80	147	125	164
St. Johns	31	45	78	64	76
Florida (Coastal Area)	12,287	16,398	31,492	27,528	30,955
Bryan	7	13	33	76	160
Camden	-1	-3	-3	2	7
Chatham	1,483	1,736	2,095	2,033	2,259
Effingham	27	41	76	43	80
Glynn	10,552	17,391	20,695	16,854	15,441
Liberty	46	63	103	70	75
Long	6	10	22	35	73
McIntosh	8	13	29	32	57
Georgia (Coastal Area)	12,129	19,265	23,050	19,146	18,152
Brunswick	17	18	28	37	52
Columbus	39	45	74	53	71
New Hanover	11,076	19,146	17,950	12,612	13,428
Pender	32	42	73	49	52
North Carolina (Coastal Area)	11,165	19,251	18,126	12,751	13,603
Beaufort	185	274	488	263	285
Berkeley	34	37	68	43	65
Charleston	707	957	28,887	6,814	10,125
Colleton	14	10	19	20	33
Dorchester	34	40	74	32	33
Georgetown	35	48	93	50	59
Hampton	5	5	7	7	13
Harry	107	147	252	153	180
Jasper	9	11	27	46	88
Williamsburg	22	21	62	34	47
South Carolina (Coastal Area)	1,152	1,550	29,978	7,461	11,019
South Atlantic Region	36,733	56,464	102,646	66,885	73,720
U.S.A.	78,000	119,000	158,000	112,000	107,000

Table XXII
Scenario NC1-I - SUMMARY OF ECONOMIC IMPACTS
Per Capita Income Impact Estimates (in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	9	9	9	10	11
Clay	9	8	8	8	8
Duval	8	12	18	15	15
Flagler	-10	-10	-11	-12	-12
Nassau	1	1	1	0	-2
Putnam	0	-2	-4	-5	-5
St. Johns	-2	-2	-2	-2	-1
Florida (Coastal Area)	8	10	16	13	13
Bryan	0	1	2	2	11
Camden	-2	1	1	1	2
Chatham	7	10	13	14	19
Effingham	6	6	7	8	11
Glynn	78	121	136	113	102
Liberty	6	8	10	9	10
Long	0	2	3	3	5
McIntosh	-4	-1	1	0	2
Georgia (Coastal Area)	18	27	30	26	26
Brunswick	-3	-2	-1	-1	-1
Columbus	-3	-3	-3	-3	-2
New Hanover	60	95	88	66	66
Pender	0	2	4	4	5
North Carolina (Coastal Area)	36	61	57	42	42
Beaufort	5	9	12	9	9
Berkeley	0	0	0	0	0
Charleston	1	2	35	8	9
Colleton	-4	-2	-2	-2	-1
Dorchester	2	2	2	2	3
Georgetown	-1	0	0	0	1
Hampton	-5	-2	-2	-2	1
Harry	3	7	8	8	9
Jasper	-2	0	1	3	6
Williamsburg	-1	0	1	2	6
South Carolina (Coastal Area)	1	3	22	7	8
South Atlantic Region	10	16	23	16	16
U.S.A.	0	1	1	0	0

Table XXII
Scenario NC1-I - SUMMARY OF ECONOMIC IMPACTS
Residential Construction Impact Estimates ($1,000) in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	0	0	0	0	0
Clay	-2	-1	-1	-1	-2
Duval	398	428	1,031	836	902
Flagler	0	0	1	1	1
Nassau	0	0	0	2	3
Putnam	1	1	4	4	5
St. Johns	1	1	2	2	2
Florida (Coastal Area)	398	430	1,036	843	912
Bryan	0	0	1	2	5
Camden	0	0	-1	-1	0
Chatham	46	50	53	52	54
Effingham	0	0	1	-1	2
Glynn	412	563	884	624	485
Liberty	1	0	1	1	1
Long	1	0	0	1	2
McIntosh	1	0	1	1	2
Georgia (Coastal Area)	461	613	940	678	550
Brunswick	2	1	1	1	2
Columbus	3	1	1	1	3
New Hanover	357	591	437	444	388
Pender	1	1	1	1	1
North Carolina (Coastal Area)	363	594	440	447	393
Beaufort	6	3	5	1	4
Berkeley	2	0	0	0	2
Charleston	26	17	1,210	121	304
Colleton	1	0	0	0	2
Dorchester	1	0	0	-1	1
Georgetown	1	0	1	1	1
Hampton	1	0	0	0	0
Harry	3	1	-1	-2	2
Jasper	1	0	0	1	2
Williamsburg	2	0	-2	0	1
South Carolina (Coastal Area)	44	21	1,214	120	317
South Atlantic Region	1,265	1,657	3,629	2,089	2,172
U.S.A.	0	0	0	0	0

Table XXII
Scenario NC1-I - SUMMARY OF ECONOMIC IMPACTS
Private Investment Impact Estimates ($1,000) in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	0	0	0	2	3
Clay	-2	-2	-1	0	1
Duval	17,168	59,502	39,091	7,149	8,281
Flagler	0	0	0	1	1
Nassau	0	0	0	3	6
Putnam	0	1	3	9	15
St. Johns	1	2	3	6	9
Florida (Coastal Area)	17,167	59,503	39,098	7,170	8,315
Bryan	0	0	1	3	7
Camden	0	-1	-1	0	0
Chatham	91	105	116	137	164
Effingham	0	0	3	-5	7
Glynn	17,225	20,542	37,108	4,458	2,203
Liberty	1	1	1	1	2
Long	0	0	1	2	4
McIntosh	1	3	4	5	8
Georgia (Coastal Area)	17,318	20,650	37,231	4,606	2,392
Brunswick	1	1	2	5	9
Columbus	3	1	1	5	8
New Hanover	17,074	42,404	35,966	1,877	1,386
Pender	1	0	1	4	4
North Carolina (Coastal Area)	17,079	42,407	35,970	1,890	1,406
Beaufort	6	3	6	4	9
Berkeley	2	-1	-1	1	5
Charleston	35	28	60,376	1,379	2,278
Colleton	1	0	-1	2	6
Dorchester	1	-1	0	0	2
Georgetown	1	0	0	0	2
Hampton	1	0	0	0	1
Harry	3	1	1	8	16
Jasper	1	0	1	3	6
Williamsburg	2	0	1	2	6
South Carolina (Coastal Area)	53	29	60,382	1,399	2,330
South Atlantic Region	51,617	122,588	172,681	15,066	14,443
U.S.A.	48,000	117,000	160,000	5,000	2,000

Table XXII
Scenario NC1-I - SUMMARY OF POPULATION IMPACTS
Impact Estimates

County and State	1980	1984	1988	1992	1996
Baker	-33	-27	-23	-27	-26
Clay	-117	-96	-87	-104	-106
Duval	1,899	2,198	4,451	3,680	3,981
Flagler	20	21	23	23	22
Nassau	-2	-2	1	13	28
Putnam	10	40	75	88	100
St. Johns	24	30	38	34	29
Florida (Coastal Area)	1,802	2,163	4,478	3,707	4,027
Bryan	4	3	9	31	48
Camden	7	-5	-9	-6	-4
Chatham	57	-42	-94	-108	-224
Effingham	-33	-29	-28	-41	-28
Glynn	2,206	3,430	3,852	2,870	2,461
Liberty	-21	-41	-43	-43	-36
Long	3	-1	2	6	18
McIntosh	17	8	9	14	21
Georgia (Coastal Area)	2,240	3,323	3,698	2,724	2,255
Brunswick	37	22	19	23	28
Columbus	72	52	49	54	63
New Hanover	1,658	2,690	2,242	1,308	1,306
Pender	11	-3	-6	-10	-12
North Carolina (Coastal Area)	1,778	2,760	2,304	1,376	1,385
Beaufort	-27	-126	-154	-156	-144
Berkeley	31	9	15	22	51
Charleston	112	64	5,682	1,167	1,969
Colleton	53	24	19	25	28
Dorchester	-11	-33	-33	-38	-30
Georgetown	31	5	8	5	7
Hampton	31	13	11	11	12
Harry	-33	-157	-156	-152	-141
Jasper	20	3	1	5	10
Williamsburg	30	5	-9	-18	-36
South Carolina (Coastal Area)	238	-194	5,383	871	1,726
South Atlantic Region	6,057	8,052	15,862	8,677	9,393
U.S.A.	0	0	0	0	0

Table XXIII
Scenario NCMAX-I - SUMMARY OF ECONOMIC IMPACTS
Earnings Impact Estimates ($1,000) in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	12	35	47	48	58
Clay	27	96	130	78	84
Duval	324	641	757	739	837
Flagler	6	13	18	16	22
Nassau	11	24	51	93	167
Putnam	50	127	180	170	245
St. Johns	30	68	98	89	119
Florida (Coastal Area)	460	1,005	1,281	1,233	1,532
Bryan	7	22	50	113	252
Camden	-1	-4	-1	4	13
Chatham	275	567	717	588	777
Effingham	26	73	106	67	122
Glynn	95	225	258	166	192
Liberty	46	93	113	86	93
Long	7	17	29	44	113
McIntosh	8	22	36	45	87
Georgia (Coastal Area)	464	1,016	1,308	1,114	1,648
Brunswick	18	23	36	50	84
Columbus	39	22	89	71	118
New Hanover	27,782	75,155	105,609	75,527	75,494
Pender	31	70	86	64	68
North Carolina (Coastal Area)	27,870	75,319	105,820	75,713	75,763
Beaufort	183	433	533	344	365
Berkeley	33	64	82	55	80
Charleston	702	1,410	1,723	1,381	1,572
Colleton	14	18	27	30	55
Dorchester	33	73	100	72	111
Georgetown	53	79	105	68	82
Hampton	6	7	8	8	17
Harry	106	237	293	210	278
Jasper	9	19	40	73	154
Williamsburg	21	36	73	46	63
South Carolina (Coastal Area)	1,142	2,374	2,986	2,288	2,777
South Atlantic Region	29,936	79,715	111,395	80,348	81,720
U.S.A.	76,000	160,000	161,000	173,000	117,000

Table XXIII
Scenario NCMAX-I - SUMMARY OF ECONOMIC IMPACTS
Per Capita Income Impact Estimates (in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	9	8	9	10	11
Clay	9	7	7	8	8
Duval	2	4	4	4	3
Flagler	-10	-10	-11	-12	-11
Nassau	1	1	1	0	-3
Putnam	0	-2	-4	-5	-5
St. Johns	-2	-2	-2	-2	-1
Florida (Coastal Area)	3	3	3	3	2
Bryan	0	1	2	3	18
Camden	-2	1	1	1	2
Chatham	4	6	5	23	19
Effingham	6	6	4	5	9
Glynn	5	5	5	5	5
Liberty	6	9	10	9	10
Long	0	3	3	4	6
McIntosh	-4	0	1	1	4
Georgia (Coastal Area)	4	6	5	14	11
Brunswick	-3	-2	-1	-1	0
Columbus	-3	-3	-3	-3	-2
New Hanover	132	323	470	406	365
Pender	0	2	4	4	5
North Carolina (Coastal Area)	85	222	322	259	240
Beaufort	5	11	12	9	9
Berkeley	0	0	1	1	0
Charleston	1	2	2	0	0
Colleton	-4	-2	-2	-2	-1
Dorchester	2	2	2	2	4
Georgetown	-1	0	0	0	1
Hampton	-5	-2	-2	-2	-1
Harry	3	7	7	7	8
Jasper	-2	0	2	4	8
Williamsburg	-1	0	1	2	6
South Carolina (Coastal Area)	1	2	3	2	3
South Atlantic Region	10	24	33	27	25
U.S.A.	0	1	1	0	0

Table XXIII
Scenario NCMAX-I - SUMMARY OF ECONOMIC IMPACTS
Residential Construction Impact Estimates ($1,000) in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	0	0	1	1	1
Clay	-2	0	1	0	-1
Duval	-4	-3	0	4	4
Flagler	0	0	1	1	1
Nassau	0	0	0	2	4
Putnam	1	3	5	6	7
St. Johns	1	1	3	3	3
Florida (Coastal Area)	-4	3	12	15	19
Bryan	0	1	2	3	6
Camden	0	0	-1	-1	0
Chatham	4	6	12	8	6
Effingham	0	1	3	0	3
Glynn	2	4	4	2	4
Liberty	1	1	2	1	2
Long	1	0	1	3	3
McIntosh	1	1	1	1	2
Georgia (Coastal Area)	8	13	24	16	26
Brunswick	2	1	1	2	2
Columbus	3	1	2	2	4
New Hanover	930	2,380	4,270	2,402	2,216
Pender	1	1	2	1	1
North Carolina (Coastal Area)	935	2,385	4,274	2,407	2,224
Beaufort	6	8	9	4	6
Berkeley	2	1	1	0	3
Charleston	24	30	42	33	44
Colleton	1	0	0	0	2
Dorchester	1	1	2	0	3
Georgetown	1	1	2	1	2
Hampton	1	0	0	0	0
Harry	3	3	2	0	4
Jasper	1	0	1	2	4
Williamsburg	2	0	-1	0	1
South Carolina (Coastal Area)	40	44	59	40	68
South Atlantic Region	978	2,444	4,369	2,477	2,337
U.S.A.	0	0	0	0	0

Table XXIII
Scenario NCMAX-I - SUMMARY OF ECONOMIC IMPACTS
Private Investment Impact Estimates ($1000) in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	0	0	1	3	5
Clay	-3	0	3	4	7
Duval	-6	-10	-8	6	26
Flagler	0	0	1	1	2
Nassau	0	0	1	4	10
Putnam	0	3	7	14	27
St. Johns	1	3	7	10	17
Florida (Coastal Area)	-7	-3	12	42	93
Bryan	0	1	2	5	10
Camden	0	-1	-1	0	1
Chatham	5	7	19	30	55
Effingham	0	1	4	1	6
Glynn	2	5	7	7	13
Liberty	1	2	2	2	3
Long	0	1	2	2	6
McIntosh	1	5	7	9	12
Georgia (Coastal Area)	10	21	42	56	107
Brunswick	2	2	4	8	16
Columbus	3	2	3	6	13
New Hanover	50,688	231,227	163,152	17,691	11,844
Pender	1	1	2	5	7
North Carolina (Coastal Area)	50,693	231,232	163,161	17,710	11,880
Beaufort	6	9	9	8	13
Berkeley	2	0	1	1	6
Charleston	34	45	65	79	121
Colleton	1	0	0	4	12
Dorchester	1	0	2	2	8
Georgetown	1	0	2	1	4
Hampton	1	0	0	0	2
Harry	3	5	9	17	34
Jasper	1	1	2	5	11
Williamsburg	2	1	1	4	9
South Carolina (Coastal Area)	53	60	92	121	221
South Atlantic Region	50,748	231,310	163,306	17,929	12,301
U.S.A.	48,000	244,000	149,000	7,000	2,000

Table XXIII
Scenario NCMAX-I - SUMMARY OF POPULATION IMPACTS
Impact Estimates

County and State	1980	1984	1988	1992	1996
Baker	2	5	6	4	5
Clay	-118	-78	-74	-93	-96
Duval	-295	-461	-489	-409	-319
Flagler	21	22	24	24	24
Nassau	-2	-1	5	20	48
Putnam	10	51	86	100	117
St. Johns	24	36	44	41	38
Florida (Coastal Area)	-393	-450	-421	-337	-206
Bryan	4	7	17	49	73
Camden	7	-6	-9	-5	-2
Chatham	-129	-172	-78	-722	-488
Effingham	-33	-14	14	-7	11
Glynn	-49	-33	-37	-47	-34
Liberty	-21	-31	-37	-37	-40
Long	3	2	4	10	30
McIntosh	17	10	11	17	31
Georgia (Coastal Area)	-202	-237	-113	-743	-409
Brunswick	37	25	24	29	40
Columbus	72	59	55	61	71
New Hanover	4,468	11,049	13,240	7,325	7,129
Pender	10	4	-1	-5	-8
North Carolina (Coastal Area)	4,588	11,136	13,317	7,409	7,233
Beaufort	-27	-115	-149	-145	-132
Berkeley	31	24	27	31	60
Charleston	110	156	223	305	416
Colleton	53	27	23	29	34
Dorchester	-11	-18	-20	-22	-2
Georgetown	31	19	16	13	14
Hampton	31	12	11	11	14
Harry	-34	-123	-128	-123	-107
Jasper	20	7	6	13	28
Williamsburg	30	13	-4	-13	-31
South Carolina (Coastal Area)	235	3	4	99	295
South Atlantic Region	4,228	10,452	12,787	6,428	6,913
U.S.A.	0	0	0	0	0

Table XXIV
Scenario SCMAX-I - SUMMARY OF ECONOMIC IMPACTS
Earnings Impact Estimates ($1,000) in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	20	42	60	60	67
Clay	50	121	176	137	136
Duval	434	795	980	427	949
Flagler	8	15	21	20	23
Nassau	16	28	50	85	132
Putnam	77	157	235	231	281
St. Johns	43	81	117	110	126
Florida (Coastal Area)	649	1,239	1,639	1,570	1,713
Bryan	10	24	44	95	213
Camden	-1	-3	-2	3	9
Chatham	387	695	921	780	909
Effingham	40	88	134	99	139
Glynn	137	273	344	257	271
Liberty	62	111	149	123	127
Long	9	18	30	45	92
McIntosh	12	24	41	49	80
Georgia (Coastal Area)	656	1,229	1,661	1,451	1,840
Brunswick	21	26	34	46	67
Columbus	53	87	115	100	120
New Hanover	119	236	334	335	465
Pender	46	85	118	101	104
North Carolina (Coastal Area)	238	434	600	583	756
Beaufort	265	528	742	568	595
Berkeley	49	82	111	84	95
Charleston	1,728	21,064	22,035	32,774	38,993
Colleton	20	25	39	42	59
Dorchester	50	89	127	106	130
Georgetown	15,096	28,347	57,978	36,035	36,498
Hampton	8	11	16	16	23
Harry	155	293	401	328	358
Jasper	13	20	37	61	114
Williamsburg	31	46	92	66	79
South Carolina (Coastal Area)	17,415	50,504	81,577	70,079	76,884
South Atlantic Region	18,958	53,406	85,477	73,685	81,193
U.S.A.	76,000	159,000	161,000	122,000	117,000

Table XXIV
Scenario SCMAX-I - SUMMARY OF ECONOMIC IMPACTS
Per Capita Income Impact Estimates (in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	9	8	9	9	9
Clay	9	7	8	7	8
Duval	3	4	4	4	3
Flagler	-10	-10	-10	-12	-11
Nassau	1	1	1	0	-2
Putnam	0	-2	-3	-5	-5
St. Johns	-2	-2	-2	-2	-1
Florida (Coastal Area)	3	3	4	3	2
Bryan	0	1	2	2	17
Camden	-2	1	1	1	2
Chatham	4	6	10	9	13
Effingham	6	7	5	4	7
Glynn	5	6	6	5	5
Liberty	6	9	11	9	10
Long	0	3	3	3	5
McIntosh	-4	0	2	2	4
Georgia (Coastal Area)	4	6	8	6	8
Brunswick	-3	-2	-1	-1	-1
Columbus	-3	-3	-2	-3	-2
New Hanover	3	4	5	4	5
Pender	0	3	5	4	6
North Carolina (Coastal Area)	-1	1	1	1	2
Beaufort	6	12	15	12	12
Berkeley	0	0	0	-1	0
Charleston	3	27	31	37	40
Colleton	-4	-2	-2	-2	-1
Dorchester	2	2	3	2	4
Georgetown	109	265	566	434	422
Hampton	-5	-2	-2	-1	0
Harry	3	7	8	7	8
Jasper	-2	0	1	2	7
Williamsburg	-1	0	1	1	6
South Carolina (Coastal Area)	9	36	63	53	55
South Atlantic Region	2	10	18	15	16
U.S.A.	0	1	1	0	0

Table XXIV
Scenario SCMAX-I - SUMMARY OF ECONOMIC IMPACTS
Residential Construction Impact Estimates ($1,000 in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	0	0	1	2	2
Clay	-2	1	2	2	1
Duval	-1	1	6	11	7
Flagler	1	0	1	1	1
Nassau	0	0	1	2	4
Putnam	2	3	7	8	8
St. Johns	2	2	3	4	3
Florida (Coastal Area)	2	9	21	27	25
Bryan	0	1	1	2	5
Camden	0	0	-1	-1	0
Chatham	8	9	12	12	13
Effingham	0	1	4	1	4
Glynn	3	5	5	5	6
Liberty	1	1	2	2	3
Long	1	0	1	1	3
McIntosh	1	1	1	1	2
Georgia (Coastal Area)	15	18	26	26	35
Brunswick	2	1	1	2	2
Columbus	3	2	2	2	4
New Hanover	2	2	5	6	9
Pender	1	2	2	3	2
North Carolina (Coastal Area)	8	8	10	12	18
Beaufort	8	10	11	11	11
Berkeley	2	1	2	2	3
Charleston	60	798	857	1,020	1,191
Colleton	1	0	1	1	2
Dorchester	2	1	2	2	3
Georgetown	574	839	1,235	1,280	1,082
Hampton	1	0	1	0	0
Harry	4	5	4	4	7
Jasper	1	1	1	2	3
Williamsburg	2	1	0	1	2
South Carolina (Coastal Area)	655	1,655	2,114	2,322	2,304
South Atlantic Region	678	1,689	2,171	2,387	2,382
U.S.A.	0	0	0	0	0

Table XXIV
Scenario SCMAX-I - SUMMARY OF ECONOMIC IMPACTS
Private Investment Impact Estimates ($1,000 in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	0	1	1	3	5
Clay	-2	1	3	5	5
Duval	1	-3	4	15	23
Flagler	0	0	1	1	1
Nassau	1	0	1	3	7
Putnam	2	3	7	14	22
St. Johns	2	3	5	9	13
Florida (Coastal Area)	4	5	24	50	75
Bryan	0	1	2	4	8
Camden	0	-1	-1	0	1
Chatham	11	11	19	34	57
Effingham	1	2	5	3	6
Glynn	4	7	8	9	12
Liberty	2	2	3	3	4
Long	0	1	1	2	6
McIntosh	1	4	6	8	11
Georgia (Coastal Area)	19	27	42	63	105
Brunswick	2	1	3	6	11
Columbus	3	2	3	6	10
New Hanover	2	1	5	13	27
Pender	2	2	2	6	6
North Carolina (Coastal Area)	9	7	12	31	55
Beaufort	10	11	13	16	19
Berkeley	3	0	2	2	5
Charleston	107	109,932	5,359	7,138	8,210
Colleton	2	0	0	3	8
Dorchester	2	1	2	3	7
Georgetown	49,211	119,616	153.064	9,529	5,684
Hampton	1	0	0	0	2
Harry	6	6	8	18	28
Jasper	1	1	1	4	8
Williamsburg	2	1	1	4	7
South Carolina (Coastal Area)	49,344	229,567	158,451	16,713	13,478
South Atlantic Region	49,376	229,605	158,529	16,857	14,213
U.S.A.	48,000	224,000	149,000	5,000	2,000

Table XXIV
Scenario SCMAX-I - SUMMARY OF POPULATION IMPACTS
Impact Estimates

County and State	1980	1984	1988	1992	1996
Baker	-29	-16	-15	-12	-13
Clay	-109	-71	-67	-68	-76
Duval	-285	-454	-491	-397	-323
Flagler	21	22	24	25	24
Nassau	-1	-2	1	16	34
Putnam	17	56	89	116	126
St. Johns	27	38	44	46	40
Florida (Coastal Area)	-359	-426	-415	-273	-188
Bryan	5	7	13	41	58
Camden	7	-6	-9	-6	-3
Chatham	-95	-146	-230	-188	-291
Effingham	-26	-9	28	19	30
Glynn	-38	-24	-29	-20	-14
Liberty	-16	-27	-33	-24	-21
Long	4	2	5	12	25
McIntosh	18	9	11	18	28
Georgia (Coastal Area)	-142	-193	-245	-149	-188
Brunswick	39	26	22	30	36
Columbus	76	62	57	71	77
New Hanover	-35	-34	-42	-25	-11
Pender	15	7	2	6	2
North Carolina (Coastal Area)	95	61	39	82	105
Beaufort	-18	-109	-144	-127	-118
Berkeley	40	31	32	54	73
Charleston	345	4,479	3,949	6,109	6,974
Colleton	56	29	23	34	36
Dorchester	-4	-13	-19	-6	4
Georgetown	4,574	6,511	10,601	5,244	4,891
Hampton	32	12	12	12	13
Harry	-22	-109	-115	-88	-82
Jasper	22	8	4	13	16
Williamsburg	34	16	2	0	-22
South Carolina (Coastal Area)	5,058	10,855	14,345	11,244	11,786
South Atlantic Region	4,653	10,297	13,724	10,905	11,515
U.S.A.	0	0	0	0	0

Table XXV
Scenario GMAX-I - SUMMARY OF ECONOMIC IMPACTS
Earnings Impact Estimates $1,000) in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	-1	16	30	46	57
Clay	-17	32	68	56	57
Duval	213	496	589	669	719
Flagler	2	7	13	14	17
Nassau	6	17	41	85	132
Putnam	1	51	101	130	174
St. Johns	9	38	68	77	93
Florida (Coastal Area)	213	658	911	1,077	1,249
Bryan	2	15	40	102	209
Camden	15,347	28,811	57,778	39,010	31,648
Chatham	93	306	498	445	519
Effingham	0	26	53	44	84
Glynn	1,131	8,812	30,020	27,697	29,782
Liberty	16	48	69	70	73
Long	4	12	23	38	89
McIntosh	3	15	29	43	74
Georgia (Coastal Area)	16,596	48,047	88,509	67,449	62,470
Brunswick	16	21	30	44	64
Columbus	15	35	51	53	71
New Hanover	9	92	165	218	342
Pender	2	26	44	47	47
North Carolina (Coastal Area)	42	174	291	362	524
Beaufort	21	179	282	250	256
Berkeley	7	26	46	49	76
Charleston	251	732	1,064	1,117	1,223
Colleton	4	3	12	21	37
Dorchester	3	27	54	53	77
Georgetown	3	31	55	49	57
Hampton	3	5	8	10	17
Harry	17	101	155	151	177
Jasper	5	13	32	65	121
Williamsburg	5	13	56	38	54
South Carolina (Coastal Area)	320	1,129	1,758	1,804	2,094
South Atlantic Region	17,171	50,008	91,467	70,692	66,346
U.S.A.	75,000	158,000	159,000	121,000	117,000

Table XXV
Scenario GMAX-I - SUMMARYOF ECONOMIC IMPACTS
Per Capita Income Impact Earnings

County and State	1980	1984	1988	1992	1996
Baker	10	9	9	11	12
Clay	9	8	7	8	8
Duval	2	4	4	4	3
Flagler	-11	-10	-11	-12	-11
Nassau	1	1	1	0	-2
Putnam	0	-2	-4	-5	-5
St. Johns	-2	-2	-2	-2	-1
Florida (Coastal Area)	3	3	4	3	3
Bryan	0	1	2	3	17
Camden	146	463	994	769	757
Chatham	5	7	8	10	23
Effingham	6	5	6	8	11
Glynn	14	121	164	179	198
Liberty	5	8	9	9	10
Long	0	3	3	4	5
McIntosh	-4	-1	1	1	3
Georgia (Coastal Area)	2	28	56	45	56
Brunswick	-3	-1	-1	-1	0
Columbus	-3	-3	-3	-3	-2
New Hanover	3	4	5	5	6
Pender	0	2	3	4	5
North Carolina (Coastal Area)	0	1	1	1	2
Beaufort	3	8	10	9	9
Berkeley	0	0	-1	0	0
Charleston	1	2	1	0	0
Colleton	-4	-2	-2	-2	-1
Dorchester	1	2	2	3	4
Georgetown	-1	0	0	0	1
Hampton	-5	-2	-2	-2	-1
Harry	2	7	8	8	9
Jasper	-2	0	2	4	7
Williamsburg	-1	0	2	3	3
South Carolina (Coastal Area)	0	2	2	2	3
South Atlantic Region	2	8	14	11	12
U.S.A.	0	1	1	0	0

Table XXV
Scenario GMAX-I - SUMMARY OF ECONOMIC IMPACTS
Residential Construction Impact Estimates ($1,000 in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	-1	0	0	1	1
Clay	-4	-2	-1	-3	-2
Duval	-8	-7	-7	-11	0
Flagler	0	0	1	1	1
Nassau	-1	-1	-1	0	4
Putnam	-1	0	2	0	5
St. Johns	-1	1	2	2	2
Florida (Coastal Area)	-13	-6	-3	-11	12
Bryan	0	0	1	2	5
Camden	583	875	1,234	7,814	1,233
Chatham	-3	-2	13	-1	-4
Effingham	-1	-1	1	-2	1
Glynn	39	668	4,282	906	880
Liberty	0	0	1	0	1
Long	0	0	1	1	2
McIntosh	1	0	1	1	2
Georgia (Coastal Area)	619	1,542	5,533	8,722	2,122
Brunswick	1	1	1	0	2
Columbus	2	0	0	0	3
New Hanover	-2	-2	0	-1	5
Pender	0	0	1	0	1
North Carolina (Coastal Area)	2	0	2	-1	11
Beaufort	1	1	2	-3	3
Berkeley	1	-1	-1	-3	3
Charleston	9	11	24	15	35
Colleton	1	0	0	-1	2
Dorchester	0	-1	0	-1	2
Georgetown	0	0	1	-1	1
Hampton	1	0	0	-1	0
Harry	0	-1	-2	-5	1
Jasper	1	0	1	2	3
Williamsburg	1	0	-2	-2	1
South Carolina (Coastal Area)	12	9	22	0	48
South Atlantic Region	620	1,543	5,554	8,709	2,192
U.S.A.	0	0	0	0	0

Table XXV
Scenario GMAX-I - SUMMARY OF ECONOMIC IMPACTS
Private Investment Impact Estimates ($1,000 in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	-1	0	1	4	6
Clay	-4	-2	0	-1	1
Duval	-5	-5	-3	-1	18
Flagler	0	0	1	1	2
Nassau	0	1	1	2	8
Putnam	-1	1	4	7	19
St. Johns	1	3	7	10	14
Florida (Coastal Area)	-10	-1	11	21	66
Bryan	0	1	2	4	8
Camden	48,679	118,684	151,396	14,817	4,903
Chatham	-1	0	26	21	31
Effingham	-1	0	1	0	3
Glynn	83	108,216	7,632	4,574	5,640
Liberty	0	0	1	1	3
Long	0	1	2	2	6
McIntosh	1	6	8	10	14
Georgia (Coastal Area)	48,761	226,907	159,068	19,428	10,608
Brunswick	2	2	3	6	11
Columbus	2	1	2	5	10
New Hanover	-2	-2	3	8	25
Pender	0	0	1	4	5
North Carolina (Coastal Area)	2	1	10	23	52
Beaufort	1	1	4	2	9
Berkeley	1	-1	0	0	7
Charleston	17	22	45	56	92
Colleton	1	0	0	2	7
Dorchester	0	-1	1	0	6
Georgetown	0	-1	0	-1	2
Hampton	1	0	0	-1	1
Harry	0	1	4	9	21
Jasper	1	0	2	4	9
Williamsburg	2	1	1	3	8
South Carolina (Coastal Area)	23	22	57	75	163
South Atlantic Region	48,776	226,930	159,145	19,547	10,889
U.S.A.	48,000	224,000	149,000	5,000	2,000

Table XXV
Scenario GMAX-I - SUMMARY OF POPULATION IMPACTS
Impact Estimates

County and State	1980	1984	1988	1992	1996
Baker	-40	-29	-25	-24	-22
Clay	-136	-103	-93	-104	-107
Duval	-317	-494	-535	-446	-356
Flagler	20	21	23	23	23
Nassau	-3	-3	3	17	36
Putnam	-3	33	70	88	101
St. Johns	18	28	38	37	32
Florida (Coastal Area)	-461	-548	-518	-408	-294
Bryan	1	4	13	43	57
Camden	4,936	7,642	12,713	8,292	5,994
Chatham	-193	-258	-223	-282	-683
Effingham	-46	-35	-32	-42	-29
Glynn	147	3,870	6,089	4,759	4,613
Liberty	-32	-46	-48	-43	-37
Long	2	0	2	7	22
McIntosh	16	9	10	16	27
Georgia (Coastal Area)	4,832	11,184	18,524	12,750	9,964
Brunswick	35	21	19	25	32
Columbus	64	47	45	53	61
New Hanover	-67	-72	-70	-64	-43
Pender	2	-7	-10	-11	-13
North Carolina (Coastal Area)	33	-12	-16	4	36
Beaufort	-42	-137	-164	-156	-145
Berkeley	13	-1	8	23	53
Charleston	14	17	114	233	332
Colleton	49	21	17	25	28
Dorchester	-25	-38	-36	-33	-19
Georgetown	15	-3	0	4	5
Hampton	31	12	11	11	12
Harry	-57	-173	-173	-161	-149
Jasper	17	3	2	10	18
Williamsburg	22	1	-23	-26	-3
South Carolina (Coastal Area)	37	-298	-246	-70	131
South Atlantic Region	4,441	10,326	17,745	12,276	9,838
U.S.A.	0	0	0	0	0

Table XXVI
Scenario FMAX-I - SUMMARY OF ECONOMIC IMPACTS
Earnings Impact Estimates ($1,000 in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	-4	-4	-2	6	10
Clay	-22	-18	-15	-5	1
Duval	33,546	70,942	108,059	92,171	97,998
Flagler	1	1	2	5	9
Nassau	2	0	13	54	95
Putnam	-7	-13	-3	42	85
St. Johns	4	5	12	31	48
Florida (Coastal Area)	33,521	70,913	108,065	92,304	98,527
Bryan	0	1	8	47	94
Camden	-1	-4	-2	2	8
Chatham	53	54	110	133	265
Effingham	-4	-10	-11	2	39
Glynn	12	29	19	24	45
Liberty	13	14	17	30	36
Long	1	1	6	23	63
McIntosh	2	0	4	16	37
Georgia (Coastal Area)	75	86	152	276	587
Brunswick	13	11	15	30	50
Columbus	10	4	2	15	34
New Hanover	-8	-13	-3	80	206
Pender	-1	-5	-6	11	15
North Carolina (Coastal Area)	14	-4	7	136	306
Beaufort	8	-3	1	26	40
Berkeley	2	-9	-4	19	60
Charleston	192	188	237	451	567
Colleton	2	-10	-10	3	20
Dorchester	-1	-11	-10	5	34
Georgetown	0	-6	-8	1	13
Hampton	1	-3	-2	2	9
Harry	4	-9	-19	12	43
Jasper	2	-1	5	30	75
Williamsburg	3	-9	-19	0	12
South Carolina (Coastal Area)	213	127	171	551	873
South Atlantic Region	33,823	77,122	108,396	93,266	100,013
U.S.A.	75,000	158,000	158,000	120,000	116,000

Table XXVI
Scenario FMAX-I - SUMMARY OF ECONOMIC IMPACTS
Per Capita Income Impact Estimates (in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	10	9	11	11	12
Clay	9	8	8	8	9
Duval	19	36	52	42	41
Flagler	-11	-11	-11	-12	-12
Nassau	1	1	1	0	-2
Putnam	0	2	-4	-5	-5
St. Johns	-2	-2	-2	-2	-1
Florida (Coastal Area)	17	31	44	36	36
Bryan	0	1	1	2	10
Camden	-2	1	1	1	2
Chatham	5	8	8	17	12
Effingham	5	7	7	9	12
Glynn	5	5	5	5	5
Liberty	5	8	9	9	10
Long	0	2	3	3	5
McIntosh	-5	-2	-1	-1	0
Georgia (Coastal Area)	4	7	7	12	9
Brunswick	-3	-1	-1	-1	0
Columbus	-3	-3	-3	-3	-2
New Hanover	3	4	5	6	6
Pender	0	2	3	4	5
North Carolina (Coastal Area)	0	1	1	2	2
Beaufort	2	6	7	6	7
Berkeley	0	0	0	0	1
Charleston	1	1	1	0	0
Colleton	-4	-2	-2	-2	1
Dorchester	1	2	2	3	4
Georgetown	-1	1	1	1	2
Hampton	-5	-2	-3	-2	-1
Harry	2	7	8	8	9
Jasper	-3	0	1	3	8
Williamsburg	-1	0	1	3	3
South Carolina (Coastal Area)	0	2	2	2	2
South Atlantic Region	10	19	26	22	21
U.S.A.	0	1	1	0	0

Table XXVI
Scenario FMAX-I - SUMMARY OF ECONOMIC IMPACTS
Residential Construction Impact Estimates ($1,000 in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	-1	-1	-1	-1	0
Clay	-4	-3	-4	-3	-3
Duval	1,235	2,090	2,997	3,031	2,999
Flagler	0	0	1	1	1
Nassau	-1	-1	0	1	3
Putnam	-1	-1	0	2	2
St. Johns	0	0	0	1	1
Florida (Coastal Area)	1,230	2,085	2,993	3,030	3,002
Bryan	0	0	0	1	3
Camden	0	0	-1	-1	0
Chatham	-4	-9	-1	-8	-4
Effingham	-1	-2	-2	-2	0
Glynn	-1	-2	-4	-3	-1
Liberty	0	-2	-1	-1	0
Long	0	0	0	0	2
McIntosh	0	0	0	0	1
Georgia (Coastal Area)	-3	-15	-8	-13	1
Brunswick	1	0	1	1	1
Columbus	2	-1	-1	0	2
New Hanover	-2	-5	-5	-3	2
Pender	0	-1	-1	0	0
North Carolina (Coastal Area)	1	-5	-6	-2	5
Beaufort	0	-5	-6	-5	-3
Berkeley	0	-2	-2	-1	2
Charleston	7	-5	-3	4	17
Colleton	1	0	-1	0	1
Dorchester	0	-2	-2	-2	0
Georgetown	0	-2	-2	-1	0
Hampton	1	-1	0	0	0
Harry	-1	-4	-8	-7	-3
Jasper	1	0	0	1	2
Williamsburg	0	-1	-3	-2	-1
South Carolina (Coastal Area)	9	-21	-26	-16	14
South Atlantic Region	1,233	2,043	2,952	2,999	3,022
U.S.A.	0	0	0	0	0

Table XXVI
Scenario FMAX-I - SUMMARY OF ECONOMIC IMPACTS
Private Investment Impact Estimates ($1,000 in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	-1	-1	-1	0	1
Clay	-5	-5	-4	-2	0
Duval	51,930	232,014	163,519	20,813	19,929
Flagler	0	0	0	1	1
Nassau	-1	-2	-1	2	5
Putnam	-2	-3	-2	5	12
St. Johns	0	0	1	5	9
Florida (Coastal Area)	51,921	232,003	163,511	20,823	19.952
Bryan	0	0	0	2	6
Camden	0	-1	-1	0	0
Chatham	-5	-17	-7	-8	-9
Effingham	-1	-2	-2	-2	1
Glynn	-2	-3	-4	0	5
Liberty	0	-1	-1	0	1
Long	0	0	0	1	4
McIntosh	0	0	1	2	3
Georgia (Coastal Area)	-8	-24	-14	-7	28
Brunswick	1	0	1	5	9
Columbus	2	-1	-1	2	6
New Hanover	-5	-9	-9	0	15
Pender	0	-1	-1	3	5
North Carolina (Coastal Area)	-2	-11	-11	10	35
Beaufort	-1	-8	-8	-4	1
Berkeley	0	-3	-3	0	7
Charleston	11	-8	-4	21	46
Colleton	1	-2	-2	1	6
Dorchester	-1	-3	-3	-1	3
Georgetown	0	-3	-3	-2	0
Hampton	1	-1	0	0	1
Harry	-2	-7	-9	0	10
Jasper	0	0	0	2	5
Williamsburg	1	-2	-5	-2	2
South Carolina (Coastal Area)	10	-37	-38	15	81
South Atlantic Region	51,920	231,930	163,449	20,842	20,096
U.S.A.	48,000	224,000	149,000	5,000	2,000

Table XXVI
Scenario FMAX-I - SUMMARY OF POPULATION IMPACTS
Impact Estimates

County and State	1980	1984	1988	1992	1996
Baker	-41	-38	-40	-38	-37
Clay	-138	-123	-128	-128	-129
Duval	5,918	12,124	17,319	13,739	13,814
Flagler	19	19	20	21	21
Nassau	-3	-6	-4	10	27
Putnam	-5	17	43	68	81
St. Johns	17	20	24	26	22
Florida (Coastal Area)	5,767	12,013	17,233	13,698	13,800
Bryan	1	-2	-1	18	21
Camden	7	-6	-9	-6	-3
Chatham	-200	-327	-325	-601	-356
Effingham	-48	-68	-77	-73	-60
Glynn	-72	-84	-98	-88	-74
Liberty	-33	-58	-68	-57	-49
Long	1	-5	-4	2	14
McIntosh	16	5	4	9	15
Georgia (Coastal Area)	-328	-545	-579	-796	-492
Brunswick	33	15	10	18	25
Columbus	63	37	28	41	50
New Hanover	-70	-96	-112	-94	-71
Pender	2	-16	-25	-21	-22
North Carolina (Coastal Area)	28	-60	-99	-55	-18
Beaufort	-44	-155	-190	-176	-164
Berkeley	11	-21	-26	2	38
Charleston	5	-90	-73	93	195
Colleton	49	16	8	19	23
Dorchester	-26	-54	-67	-54	-39
Georgetown	14	-19	-29	-16	-12
Hampton	31	11	10	11	12
Harry	-59	-212	-231	-207	-194
Jasper	16	-2	-8	-1	-2
Williamsburg	21	-9	-48	-41	-17
South Carolina (Coastal Area)	17	-535	-653	-370	-162
South Atlantic Region	5,484	10,874	15,902	12,477	13,128
U.S.A.	0	0	0	0	0

Table XXVII
Scenario GASC-I - SUMMARY OF ECONOMIC IMPACTS
Earnings Impact Estimates ($1,000 in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	22	25	57	55	69
Clay	54	62	151	89	96
Duval	512	495	869	805	878
Flagler	9	10	22	19	23
Nassau	15	23	52	101	166
Putnam	81	93	205	186	256
St. Johns	45	54	113	99	125
Florida (Coastal Area)	737	764	1,470	1,354	1,614
Bryan	11	20	164	137	167
Camden	11,413	20,843	28,775	21,110	22,367
Chatham	19,549	17,776	22,385	22,402	23,899
Effingham	44	51	118	75	126
Glynn	1,278	1,448	6,164	5,752	5,561
Liberty	67	69	119	81	88
Long	10	16	34	50	113
McIntosh	13	20	133	80	87
Georgia (Coastal Area)	32,385	40,242	57,891	49,668	52,407
Brunswick	21	22	37	47	73
Columbus	57	51	103	79	119
New Hanover	136	134	313	306	488
Pender	49	47	104	71	78
North Carolina (Coastal Area)	263	255	557	503	758
Beaufort	290	301	662	378	416
Berkeley	53	43	98	64	89
Charleston	1,031	1,030	40,094	7,219	10,782
Colleton	19	13	29	33	54
Dorchester	54	48	116	82	117
Georgetown	6,532	13,279	15,064	12,814	13,697
Hampton	8	8	13	14	22
Harry	168	165	353	232	294
Jasper	14	16	8,535	-40	29
Williamsburg	30	26	81	52	72
South Carolina (Coastal Area)	8,197	14,930	65,046	20,848	25,572
South Atlantic Region	41,582	56,191	124,963	72,393	80,351
U.S.A.	122,000	129,000	195,000	123,000	119,000

Table XXVII
Scenario GASC-I - SUMMARY OF ECONOMIC IMPACTS
Per Capita Income Impact Estimates (in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	9	9	10	10	11
Clay	9	8	8	8	8
Duval	3	4	5	4	3
Flagler	-10	-10	-10	-11	-11
Nassau	1	1	1	0	-3
Putnam	0	-2	-3	-5	-5
St. Johns	-1	-2	-2	-2	-1
Florida (Coastal Area)	3	3	4	3	3
Bryan	0	1	3	5	17
Camden	131	405	615	534	541
Chatham	38	47	40	58	68
Effingham	6	6	9	8	11
Glynn	15	16	5	34	50
Liberty	6	9	11	9	10
Long	0	3	4	4	6
McIntosh	-3	0	7	-1	3
Georgia (Coastal Area)	30	43	42	55	63
Brunswick	-3	-2	-1	-1	-1
Columbus	-3	-3	-2	-3	-2
New Hanover	3	4	5	5	6
Pender	0	2	5	4	6
North Carolina (Coastal Area)	0	1	2	1	2
Beaufort	6	10	14	10	10
Berkeley	0	0	0	0	0
Charleston	2	2	51	9	10
Colleton	-4	-2	-2	-2	-1
Dorchester	2	2	3	3	4
Georgetown	62	148	191	173	167
Hampton	-4	-2	-2	-2	-1
Harry	3	7	9	8	9
Jasper	-2	0	84	0	3
Williamsburg	-1	0	2	3	3
South Carolina (Coastal Area)	5	13	42	18	19
South Atlantic Region	7	12	18	16	17
U.S.A.	1	1	1	0	0

Table XXVII
Scenario GASC-I - SUMMARY OF ECONOMIC IMPACTS
Residential Construction Impact Estimates ($1,000 in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	0	0	1	1	2
Clay	-2	-1	1	0	0
Duval	-3	-4	-1	6	5
Flagler	0	0	1	1	1
Nassau	0	0	0	3	5
Putnam	1	2	5	6	7
St. Johns	1	1	3	3	3
Florida (Coastal Area)	-3	0	10	19	22
Bryan	0	1	8	5	4
Camden	427	620	1,073	726	681
Chatham	695	503	732	706	711
Effingham	0	0	2	0	3
Glynn	43	48	448	156	113
Liberty	1	0	0	1	2
Long	1	0	1	1	3
McIntosh	1	0	7	3	3
Georgia (Coastal Area)	1,168	1,172	2,273	1,599	1,520
Brunswick	1	1	1	2	2
Columbus	3	1	1	2	4
New Hanover	1	0	3	4	9
Pender	1	1	2	2	2
North Carolina (Coastal Area)	7	3	7	9	17
Beaufort	8	3	8	4	7
Berkeley	2	0	1	1	3
Charleston	29	19	1,228	127	320
Colleton	1	0	0	1	2
Dorchester	1	0	1	1	3
Georgetown	254	420	338	434	410
Hampton	1	0	0	0	0
Harry	4	1	0	0	5
Jasper	1	0	1	1	0
Williamsburg	2	0	-1	0	1
South Carolina (Coastal Area)	301	444	1,528	568	751
South Atlantic Region	1,471	1,618	3,867	2,194	2,310
U.S.A.	0	0	0	0	0

Table XXVII
Scenario GASC-I - SUMMARY OF ECONOMIC IMPACTS
Private Investment Impact Estimates ($1,000 in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	0	0	1	4	6
Clay	-2	-1	2	3	4
Duval	-5	-4	5	4	3
Flagler	0	0	1	1	2
Nassau	0	0	1	5	10
Putnam	1	2	5	14	25
St. Johns	1	3	7	11	17
Florida (Coastal Area)	-5	2	11	56	93
Bryan	0	1	17	11	8
Camden	32,311	77,838	71,294	4,298	2,974
Chatham	108,877	1,921	3,803	4,133	4,218
Effingham	0	1	3	2	5
Glynn	88	109	1,698	1,740	2,283
Liberty	2	1	0	1	3
Long	0	1	2	3	7
McIntosh	1	6	15	12	15
Georgia (Coastal Area)	141,279	79,877	76,831	10,200	9,513
Brunswick	2	2	4	9	15
Columbus	3	1	2	7	12
New Hanover	0	0	4	15	36
Pender	1	1	2	5	7
North Carolina (Coastal Area)	6	4	12	36	69
Beaufort	9	4	9	8	15
Berkeley	2	-1	0	2	6
Charleston	42	33	88,112	1,425	2,347
Colleton	1	1	0	4	10
Dorchester	1	0	2	3	8
Georgetown	16,503	41,905	35,752	1,907	1,479
Hampton	1	0	0	1	2
Harry	4	3	8	18	32
Jasper	1	1	21,631	-1	1
Williamsburg	2	1	1	5	10
South Carolina (Coastal Area)	16,566	42,000	145,515	3,372	3,909
South Atlantic Region	157,847	121,883	222,370	13,663	13,584
U.S.A.	154,000	117,000	209,000	4,000	2,000

Table XXVII
Scenario GASC-I - SUMMARY OF POPULATION IMPACTS
Impact Estimates

County and State	1980	1984	1988	1992	1996
Baker	-28	-25	-18	-19	-16
Clay	-110	-94	-77	-92	-92
Duval	-286	-496	-539	-420	-331
Flagler	21	21	24	24	24
Nassau	-2	-1	3	22	46
Putnam	15	41	80	101	119
St. Johns	26	31	42	42	39
Florida (Coastal Area)	-364	-522	-484	-341	-210
Bryan	5	5	77	54	35
Camden	3,615	5,398	6,566	4,374	4,429
Chatham	3,458	2,299	3,351	2,360	2,060
Effingham	-27	-26	-12	-26	-8
Glynn	182	179	1,738	1,058	675
Liberty	-16	-40	-47	-41	-33
Long	5	1	5	11	30
McIntosh	17	9	45	42	34
Georgia (Coastal Area)	7,239	7,827	11,721	7,832	7,221
Brunswick	38	23	21	29	39
Columbus	74	52	50	61	71
New Hanover	-35	-61	-53	-45	-16
Pender	14	-3	-3	-5	-5
North Carolina (Coastal Area)	90	11	16	40	88
Beaufort	-22	-126	-155	-146	-130
Berkeley	36	10	20	33	64
Charleston	154	69	7,726	1,246	2,089
Colleton	54	24	18	29	34
Dorchester	-5	-30	-24	-20	0
Georgetown	1,812	2,857	2,537	1,778	1,853
Hampton	31	13	10	12	14
Harry	-24	-154	-145	-134	-118
Jasper	21	5	3,382	-20	0
Williamsburg	33	6	-17	-20	4
South Carolina (Coastal Area)	2,090	2,673	13,353	2,756	3,810
South Atlantic Region	9,055	9,989	24,606	10,287	10,910
U.S.A.	0	0	0	0	0

Table XXVIII
Scenario GASC-II - SUMMARY OF ECONOMIC IMPACTS
Earnings Impact Estimates ($1,000 in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	12	20	50	47	60
Clay	30	45	128	70	78
Duval	354	491	973	1,081	1,213
Flagler	4	6	16	12	14
Nassau	11	19	46	84	125
Putnam	33	54	155	125	167
St. Johns	22	35	92	75	93
Florida (Coastal Area)	466	671	1,460	1,495	1,747
Bryan	6	15	153	93	117
Camden	11,413	20,592	27,629	19,564	22,163
Chatham	239	332	871	751	1,040
Effingham	20	36	100	57	73
Glynn	1,181	1,378	6,092	5,712	5,513
Liberty	35	50	98	66	73
Long	6	12	27	34	67
McIntosh	5	15	126	69	62
Georgia (Coastal Area)	12,906	22,430	35,096	26,346	29,110
Brunswick	15	20	37	45	59
Columbus	20	30	82	59	86
New Hanover	60	96	275	260	381
Pender	19	28	81	37	41
North Carolina (Coastal Area)	113	175	475	400	567
Beaufort	117	183	520	248	283
Berkeley	21	30	85	48	49
Charleston	520	737	39,792	6,990	10,524
Colleton	5	7	26	31	42
Dorchester	22	34	99	62	76
Georgetown	6,498	13,055	14,363	11,870	13,626
Hampton	3	5	11	12	15
Harry	73	110	308	206	263
Jasper	7	13	8,525	-64	-24
Williamsburg	11	18	51	43	51
South Carolina (Coastal Area)	7,276	14,194	63,778	19,447	24,907
South Atlantic Region	20,762	37,470	100,808	47,688	56,330
U.S.A.	77,000	118,000	183,000	110,000	106,000

Table XXVIII
Scenario GASC-II - SUMMARY OF ECONOMIC IMPACTS
Per Capita Income Impact Estimates

County and State	1980	1984	1988	1992	1996
Baker	0	0	0	0	0
Clay	0	0	0	0	0
Duval	0	0	1	1	1
Flagler	1	1	2	1	1
Nassau	0	0	0	0	1
Putnam	0	0	1	0	0
St. Johns	0	0	1	0	0
Florida (Coastal Area)	0	0	1	0	0
Bryan	0	1	2	4	12
Camden	133	388	553	451	540
Chatham	0	0	-5	-5	3
Effingham	0	1	3	1	1
Glynn	10	11	0	29	45
Liberty	0	1	2	0	0
Long	0	1	2	2	2
McIntosh	1	2	8	0	2
Georgia (Coastal Area)	-1	6	1	5	12
Brunswick	0	0	1	0	0
Columbus	0	0	1	0	1
New Hanover	0	0	1	0	1
Pender	0	1	2	0	0
North Carolina (Coastal Area)	0	0	1	0	0
Beaufort	2	2	6	2	2
Berkeley	0	0	1	0	0
Charleston	1	1	51	9	10
Colleton	0	0	0	0	0
Dorchester	0	0	1	0	0
Georgetown	64	143	176	155	165
Hampton	0	1	1	1	1
Harry	0	0	1	0	0
Jasper	0	0	83	-2	-2
Williamsburg	0	0	0	1	-3
South Carolina (Coastal Area)	4	10	39	15	17
South Atlantic Region	1	4	9	6	7
U.S.A.	0	1	1	0	0

Table XXVIII
Scenario GASC-II - SUMMARY OF ECONOMIC IMPACTS
Residential Construction Impact Estimates ($1,000 in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	0	1	2	1	2
Clay	1	1	2	2	2
Duval	6	5	10	25	27
Flagler	0	0	0	0	0
Nassau	0	0	0	2	3
Putnam	0	1	3	3	4
St. Johns	0	1	2	2	3
Florida (Coastal Area)	8	8	19	35	41
Bryan	0	1	7	3	2
Camden	427	616	1,043	682	660
Chatham	6	7	25	22	30
Effingham	1	2	3	2	2
Glynn	42	49	449	158	112
Liberty	1	1	1	2	2
Long	1	0	1	2	2
McIntosh	0	0	7	2	2
Georgia (Coastal Area)	477	676	1,537	873	813
Brunswick	0	1	1	1	1
Columbus	0	1	1	2	2
New Hanover	1	1	4	6	8
Pender	0	1	2	1	1
North Carolina (Coastal Area)	2	4	8	10	13
Beaufort	4	4	10	6	7
Berkeley	1	0	2	2	1
Charleston	17	17	1,228	126	311
Colleton	0	0	0	1	1
Dorchester	0	0	2	2	2
Georgetown	253	418	320	405	408
Hampton	0	0	0	0	0
Harry	0	2	6	6	7
Jasper	0	0	1	0	-1
Williamsburg	0	0	1	1	1
South Carolina (Coastal Area)	277	444	1,570	548	736
South Atlantic Region	763	1,131	3,136	1,467	1,604
U.S.A.	0	0	0	0	0

Table XXVIII
Scenario GASC-II - SUMMARY OF ECONOMIC IMPACTS
Private Investment Impact Estimates ($1,000 in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	1	1	2	4	6
Clay	1	1	4	5	5
Duval	11	13	25	70	93
Flagler	0	0	1	1	1
Nassau	1	1	2	6	10
Putnam	1	1	3	10	17
St. Johns	1	2	6	9	13
Florida (Coastal Area)	14	19	42	106	144
Bryan	0	1	17	9	6
Camden	32,317	77,835	71,259	4,244	2,948
Chatham	13	13	45	69	108
Effingham	1	2	4	4	4
Glynn	86	109	16,981	1,741	2,281
Liberty	2	2	1	3	4
Long	0	1	2	2	4
McIntosh	0	7	15	13	15
Georgia (Coastal Area)	32,413	77,968	73,041	6,085	5,370
Brunswick	1	2	4	7	10
Columbus	0	1	2	5	7
New Hanover	1	2	7	17	29
Pender	1	1	2	2	3
North Carolina (Coastal Area)	3	5	15	31	50
Beaufort	3	5	11	11	14
Berkeley	0	0	2	3	4
Charleston	27	33	88,108	1,427	2,337
Colleton	0	0	0	4	7
Dorchester	1	1	3	4	6
Georgetown	16,502	41,952	35,716	1,843	1,474
Hampton	0	0	0	1	1
Harry	3	5	13	21	29
Jasper	0	1	21,631	-2	-2
Williamsburg	1	2	3	6	7
South Carolina (Coastal Area)	16,538	41,999	145,487	3,318	3,876
South Atlantic Region	48,967	119,991	218,585	9,539	9,441
U.S.A.	48,000	117,000	209,000	4,000	2,000

Table XXVIII
Scenario GASC-II -- SUMMARY OF POPULATION IMPACTS
Impact Estimates

County and State	1980	1984	1988	1992	1996
Baker	6	8	17	15	18
Clay	12	15	35	25	26
Duval	28	34	62	147	159
Flagler	0	1	2	3	4
Nassau	1	2	7	19	31
Putnam	6	8	21	25	33
St. Johns	4	5	14	16	19
Florida (Coastal Area)	57	73	158	251	290
Bryan	2	6	76	35	25
Camden	3,608	5,404	6,520	4,279	4,377
Chatham	52	63	359	324	285
Effingham	9	14	39	28	33
Glynn	231	250	1,817	1,135	742
Liberty	12	14	17	19	20
Long	3	4	8	11	20
McIntosh	1	3	40	34	23
Georgia (Coastal Area)	3,916	5,758	8,875	5,866	5,525
Brunswick	3	4	9	14	20
Columbus	2	2	10	13	16
New Hanover	11	14	39	41	56
Pender	4	5	13	9	11
North Carolina (Coastal Area)	21	26	71	78	103
Beaufort	9	10	19	30	37
Berkeley	6	7	23	18	19
Charleston	100	121	7,767	1,184	1,940
Colleton	0	0	3	7	10
Dorchester	8	11	29	26	35
Georgetown	1,783	2,855	2,509	1,715	1,852
Hampton	-1	-1	-3	1	2
Harry	14	30	56	54	62
Jasper	2	4	3,388	-20	0
Williamsburg	5	6	17	3	46
South Carolina (Coastal Area)	1,927	3,042	13,807	3,018	4,003
South Atlantic Region	5,922	8,900	22,910	9,212	9,922
U.S.A.	0	0	0	0	0

Table XXIX
Scenario GASC-III - SUMMARY OF ECONOMIC IMPACTS
Earnings Impact Estimates ($1,000 in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	26	27	58	49	63
Clay	73	77	165	102	108
Duval	565	556	931	876	987
Flagler	8	9	21	18	22
Nassau	15	29	62	131	251
Putnam	82	92	200	174	239
St. Johns	44	51	110	95	121
Florida (Coastal Area)	814	842	1,548	1,444	1,792
Bryan	12	20	164	116	126
Camden	11,412	20,567	27,265	18,459	19,927
Chatham	19,563	17,767	22,443	22,455	23,936
Effingham	48	61	129	91	115
Glynn	1,283	1,430	6,113	5,695	5,494
Liberty	68	72	123	85	91
Long	10	16	37	53	100
McIntosh	11	21	138	89	18
Georgia (Coastal Area)	32,406	39,954	56,412	47,043	49,807
Brunswick	18	22	38	54	79
Columbus	48	48	102	77	114
New Hanover	143	147	327	316	487
Pender	48	50	108	71	80
North Carolina (Coastal Area)	255	267	575	518	760
Beaufort	289	310	674	386	421
Berkeley	49	50	103	60	62
Charleston	1,021	1,062	40,107	7,171	10,732
Colleton	13	15	33	39	54
Dorchester	54	56	128	95	120
Georgetown	6,532	13,064	14,190	11,130	12,796
Hampton	5	8	14	14	21
Harry	169	179	383	263	323
Jasper	20	22	8,162	94	44
Williamsburg	26	33	72	67	76
South Carolina (Coastal Area)	8,179	14,798	63,865	19,319	24,650
South Atlantic Region	41,654	55,861	122,400	68,324	77,009
U.S.A.	122,000	129,000	195,000	122,000	119,000

Table XXIX
Scenario GASC-III - SUMMARY OF ECONOMIC IMPACTS
Per Capita Income Impact Estimates

County and State	1980	1984	1988	1992	1996
Baker	-1	-1	-1	-1	-1
Clay	0	0	0	-1	-1
Duval	1	1	1	1	1
Flagler	1	1	2	1	1
Nassau	0	1	1	0	0
Putnam	0	0	1	0	0
St. Johns	0	0	1	0	0
Florida (Coastal Area)	0	0	1	0	0
Bryan	1	1	3	12	11
Camden	133	386	533	387	441
Chatham	34	40	29	48	34
Effingham	1	0	5	4	4
Glynn	10	11	-1	29	45
Liberty	1	1	2	0	0
Long	1	1	2	2	3
McIntosh	1	1	9	1	7
Georgia (Coastal Area)	27	35	30	41	39
Brunswick	0	0	0	0	0
Columbus	0	0	1	0	1
New Hanover	0	0	0	0	1
Pender	1	1	2	1	1
North Carolina (Coastal Area)	0	0	1	0	1
Beaufort	4	4	8	4	3
Berkeley	0	0	1	0	0
Charleston	2	1	51	9	10
Colleton	0	0	0	0	0
Dorchester	0	0	1	0	0
Georgetown	63	143	171	139	151
Hampton	1	1	1	1	1
Harry	1	0	1	0	0
Jasper	1	1	154	0	0
Williamsburg	0	0	0	3	-1
South Carolina (Coastal Area)	5	11	45	14	16
South Atlantic Region	6	9	17	11	11
U.S.A.	1	1	1	0	0

Table XXIX
Scenario GASC-III - SUMMARY OF ECONOMIC IMPACTS
Residential Construction Impact Estimates ($1,000 in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	1	1	2	2	2
Clay	2	2	4	3	3
Duval	7	7	8	16	18
Flagler	0	0	1	1	1
Nassau	-1	0	1	3	6
Putnam	1	2	4	4	6
St. Johns	1	1	3	2	3
Florida (Coastal Area)	11	12	21	30	38
Bryan	0	1	8	5	3
Camden	426	617	1,037	656	598
Chatham	698	510	744	718	723
Effingham	1	2	4	3	4
Glynn	44	50	450	158	112
Liberty	2	2	2	3	3
Long	1	1	1	1	3
McIntosh	0	0	8	3	4
Georgia (Coastal Area)	1,173	1,182	2,252	1,547	1,450
Brunswick	0	0	0	1	2
Columbus	1	1	2	2	2
New Hanover	2	3	6	8	12
Pender	1	1	3	2	2
North Carolina (Coastal Area)	4	5	11	13	18
Beaufort	8	8	14	10	11
Berkeley	1	1	2	1	2
Charleston	26	26	1,231	131	316
Colleton	0	0	1	0	1
Dorchester	1	1	3	2	3
Georgetown	254	419	317	387	376
Hampton	0	0	0	0	1
Harry	3	4	9	8	9
Jasper	0	0	-1	-1	-1
Williamsburg	0	1	2	2	2
South Carolina (Coastal Area)	294	459	1,577	543	719
South Atlantic Region	1,482	1,658	3,861	2,133	2,225
U.S.A.	0	0	0	0	0

Table XXIX
Scenario GASC-II - SUMMARY OF ECONOMIC IMPACTS
Private Investment Impact Estimates ($1,000 in 1972 Dollars)

County and State	1980	1984	1988	1992	1996
Baker	1	1	2	4	6
Clay	2	2	5	6	7
Duval	9	11	9	34	52
Flagler	0	0	1	1	2
Nassau	0	22	22	39	86
Putnam	1	2	4	12	22
St. Johns	1	3	6	11	17
Florida (Coastal Area)	14	41	50	107	191
Bryan	0	1	18	11	6
Camden	32,311	77,835	71,252	4,213	2,872
Chatham	108,884	1,930	3,818	4,150	4,232
Effingham	1	3	5	5	6
Glynn	89	111	1,697	1,737	2,276
Liberty	2	2	2	3	4
Long	0	1	2	3	7
McIntosh	0	9	16	15	19
Georgia (Coastal Area)	141,290	79,892	76,809	10,137	9,422
Brunswick	1	2	4	9	15
Columbus	1	1	2	6	10
New Hanover	2	3	7	19	37
Pender	1	1	3	5	7
North Carolina (Coastal Area)	5	7	16	39	69
Beaufort	9	9	16	15	19
Berkeley	1	1	2	3	3
Charleston	39	42	88,106	1,429	2,346
Colleton	0	0	0	4	9
Dorchester	1	2	4	6	9
Georgetown	16,503	41,954	35,708	1,803	1,403
Hampton	0	0	0	1	1
Harry	5	7	16	26	38
Jasper	0	0	21,612	2	3
Williamsburg	1	4	6	10	12
South Carolina (Coastal Area)	16,558	42,019	145,470	3,298	3,843
South Atlantic Region	157,867	121,959	222,346	13,580	13,525
U.S.A.	154,000	117,000	209,000	4,000	2,000

Table XXIX
Scenario GASC-III - SUMMARY OF POPULATION IMPACTS
Impact Estimates

County and State	1980	1984	1988	1992	1996
Baker	13	12	23	19	22
Clay	27	26	49	37	39
Duval	47	33	42	93	105
Flagler	1	1	3	4	5
Nassau	0	3	9	25	47
Putnam	16	16	31	35	46
St. Johns	8	9	18	20	24
Florida (Coastal Area)	111	100	174	233	289
Bryan	4	7	77	22	31
Camden	3,607	5,405	6,507	4,231	4,184
Chatham	3,661	2,619	3,779	2,755	3,205
Effingham	20	35	33	25	32
Glynn	253	262	1,829	1,141	747
Liberty	20	20	25	26	26
Long	4	6	13	18	31
McIntosh	1	9	44	40	-15
Georgia (Coastal Area)	7,569	8,363	12,307	8,258	8,241
Brunswick	5	6	12	19	27
Columbus	7	7	15	16	21
New Hanover	30	26	53	53	73
Pender	10	10	20	16	19
North Carolina (Coastal Area)	52	49	99	105	141
Beaufort	19	18	29	37	44
Berkeley	18	17	35	27	29
Charleston	180	176	7,835	1,230	1,985
Colleton	2	2	5	9	12
Dorchester	19	19	41	40	54
Georgetown	1,795	2,864	2,512	1,681	1,786
Hampton	-2	-1	-3	1	3
Harry	33	51	82	75	85
Jasper	3	4	2,001	29	14
Williamsburg	11	12	32	-5	39
South Carolina (Coastal Area)	2,079	3,161	12,569	3,125	4,052
South Atlantic Region	9,812	11,673	25,149	11,721	12,722
U.S.A.	0	0	0	0	0

Table XXX
OCS Induced Population Impacts

State & Year	Scenario NC1-I	NCMAX-I	SCMAX-I	GMAX-I	FMAX-I	GASC-I	GASC-II	GASC-III
North Carolina								
1984	2,760	11,136	61	-12	-60	11	26	49
1988	2,304	13,317	39	-16	-99	16	71	99
1992	1,376	7,409	82	4	-55	40	78	105
1996	1,385	7,233	105	36	-18	88	103	141
South Carolina								
1984	-194	3	6,511	-298	-535	6	3,042	3,161
1988	5,383	4	10,601	-246	-653	-17	13,807	25,149
1992	871	99	5,244	-70	-370	-20	3,018	11,721
1996	1,726	295	4,891	131	-162	4	9,922	12,722
Georgia								
1984	3,323	-237	-193	11,184	-545	7,827	5,758	8,363
1988	3,698	-113	-245	18,524	-579	11,721	8,875	12,307
1992	2,724	-743	-149	12,750	-796	7,832	5,866	8,258
1996	2,255	-409	-188	9,964	-492	7,221	5,523	8,241
Florida								
1984	2,163	-450	-426	-548	12,013	-522	73	100
1988	4,478	-421	-415	-518	17,233	-484	158	174
1992	3,707	-337	-273	-408	13,698	-341	251	233
1996	4,027	-206	-188	-294	13,800	-210	290	289
South Atlantic Region								
1984	8,052	10,452	10,297	10,326	10,874	2,673	8,900	11,673
1988	15,862	12,787	13,724	17,745	15,902	13,353	22,910	25,149
1992	8,677	6,428	10,905	12,276	12,477	2,756	9,212	11,721
1996	9,393	6,913	11,515	9,838	13,128	3,810	9,922	12,722

Table XXXI

Range of Estimated Population Impacts
Summary of Eight Additional Scenarios

State & County	1980 Low	1980 High	1980 Average (Rounded)	Year 1988 Low	1988 High	1988 Average (Rounded)	1996 Low	1996 High	1996 Average (Rounded)
North Carolina									
Brunswick	3	39	28	9	24	17	20	40	31
Columbus	2	76	54	10	57	39	16	77	54
New Hanover	-30	4,468	741	-112	13,240	1,912	-71	7,129	1,053
Pender	2	15	9	-25	20	-10	-22	19	-4
South Carolina									
Beaufort	-44	19	-19	-190	29	-114	-164	44	-94
Berkeley	6	40	23	-26	35	17	19	73	48
Charleston	5	345	128	-73	7,835	4,153	195	6,974	1,987
Colleton	0	56	40	3	23	15	10	36	26
Dorchester	-26	19	-7	-67	41	-16	-39	54	0
Georgetown	14	4,574	1,257	-29	10,601	2,269	-12	4,891	1,299
Hampton	-2	32	23	-3	12	1	2	14	11
Horry	-59	33	-23	-231	82	-101	-194	85	-81
Jasper	2	22	15	-8	3.388	1,097	-2	24	10
Williamsburg	5	34	23	-48	32	-5	-36	46	-3
Georgia									
Bryan	1	5	3	-1	77	35	21	73	44
Camden	7	4,936	1,974	-9	12,713	4,034	-4	5,994	2,372
Chatham	-200	3,661	1,095	-325	3,779	817	-683	3,205	439
Effingham	-48	20	-23	-77	39	-4	-60	33	-3
Glynn	-72	2,206	358	-98	6,089	2,096	-74	4,613	1,140
Liberty	-33	20	-13	-68	25	-29	-49	26	-20
Long	1	5	3	-4	13	4	14	31	24
McIntosh	1	18	13	4	45	22	-15	34	21
Florida									
Baker	-41	13	-19	-38	19	10	-37	22	-8
Clay	-138	27	-86	-128	49	-55	-129	39	-68
Duval	-317	5,918	601	-539	17,319	2,477	-356	13,814	2,091
Flagler	0	21	15	2	24	18	4	24	18
Nassau	-3	1	-2	-4	9	3	27	48	37
Putnam	-5	17	8	21	89	62	33	126	90
St. John	4	26	19	14	44	33	19	40	30

scenario, the levels of induced private investment are also very high. Again it should be remembered that these are extreme cases.

E. Impact on Population

Population impacts are most closely related to job opportunities. As employment rises—workers shift jobs or unemployed workers move to employment locations. Assuming that a certain number bring families, population levels will move in the same direction but to a higher level than the employment impacts. The range and average (Table XXXI) summary impacts show again a wider range and a higher average than the original five scenarios (Tables E-24, 25, and 26) in Chapter III. The intent of the extra scenarios was to examine just such a wider set of possible impacts.

F. Alternative Forecasts

An alternative economic impact model has been developed by the Georgia Economic Forecasting Project established by the College of Business Administration at the University of Georgia. The model is entitled Georgia Economic Forecasting Model and is basically an input-output computer simulation of the Georgia economy.

Since Georgia presently lacks an integrated oil and gas industry, predicted offshore related, direct impacts were grafted onto the basic structure of the model as a Quasi industry "OCS". The computer simulation then used the five original scenarios of the Harris model as input to produce an estimation of future economic impacts. Since this simulation is only of the Georgia economy, it is different than the Harris model which is national in scope. In addition the Harris model uses location analysis whereas the Georgia model used strictly input-output methods of calculation. Therefore, it is not surprising that there are differences in results between the two forecasts.

The computer products for the Georgia model were furnished to the Bureau of Land Management by the Georgia State Planning Office. Unfortunately, space prohibits their reproduction in this document. The effort that the state of Georgia expended in this endeavor in economic forecasting is greatly appreciated.

Keeping in mind the fact that these models are merely simulations and are limited in accuracy by assumptions and other technical problems, these models are useful in making estimates of possible impacts. No one claims to have a "crystal ball" and no particular model can claim to be absolutely correct. The reason that the Bureau of Land Management chose to contract for the Harris model included the national scope of the model which allows a consistent inter-state viewpoint.

For further information on the Georgia model contact Mr. Brian Finch of the University of Georgia, College of Business Administration, Athens, Georgia 30602.

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Appendix L

MIT Oil Spill Model

a. MIT Model

One of the first trajectory studies for the U.S. South Atlantic OCS area was conducted by Stewart et al. (1974) at the request of the Council on Environmental Quality. In developing their model, they decided to use the observation of Smith (1968) that oil on the surface tends to move at a velocity approximately equal to the vectorial sum of three percent of the surface wind velocity plus the current velocity. In using Smith's observations, Stewart et al. (1974) modified it somewhat so that the current velocity was divided into two components: the tidal current and the residual current. The formula thus takes on the following form:

$$\vec{U}_{oil} = 0.03\,\vec{U}_{wind} + \vec{U}_{tidal} + \vec{U}_{residual}$$

The residual current is defined by the authors as meaning all currents whose period of fluctuation is large with respect to life of the spill. Using this definition, the model ignores medium scale phenomena, such as Gulf Stream eddies and shelf waves, which introduces some degree of error. Another reason for error is the lack of sufficient wind and current data for the Atlantic OCS. The authors were forced to use the only information available: drift bottles and card data, current charts, the geostrophy of the region, and plain old "oceanographic intuition". This assumption will generate minor errors as long as the spill trajectory covers a sizable number of tidal cycles, in which case the net transport due to tidal action will be quite small within U.S. South Atlantic region.

Wind movements were incorporated into the model with a number of assumptions: that the wind changes direction every three hours, that the wind blows from only eight directions, and that the directional shift only depends on the wind's present direction. Wind changes can occur more frequently than every three hours, and smaller-scale fluctuations may be missed due to the use of three hourly intervals. Furthermore, the wind does not blow from only eight directions plus calm but rather can come from any point of the compass. The randomizing process which is used to pattern wind movements has not been shown to accurately pattern true wind histories, although Stewart (1973) determined that the above assumptions account for only a 10% error of net spill dispersion.

Finally, as was the case with the currents, there is a lack of reliable wind data available. The authors of the model were therefore forced to obtain most of their wind data from onshore weather stations. This greatly limits the wind model since frequently onshore wind data differ considerably from offshore wind data.

In determining oil spill trajectories for offshore regions, the problem regarding the uncertainty surrounding the specification of the ambient current components is encountered. The best available data was used, however, it is recognized to be very sparse and based on drift bottles studies which are few and have sometimes only resulted in a portion of the drift bottles being recovered. It was further assumed that the nonwind-related motions, of which these currents are composed, are weak compared to the wind-induced motions.

In order to test the validity of the trajectory model, it was decided to conduct tests using ballasted drift bottles launched in the areas of the hypothetical drill sites. For the purposes of characterizing the tests, the following parameters were used: percentage recovered, recovery region and minimum and average time to recovery. Due to various probabilities tests, it was decided that the drift bottles do not act independently but rather that they travel in a group. This statement implies, therefore, that the surface boundary layer is characterized by large scale, random fluctuations.

MIT computed the trajectories of offshore oil spills for several hypothetical Eastcoast Drilling Sites (EDS's) within the Georgia Embayment Region (Figure L-1). Hypothetical spills were launched by EDS 10, 11, 12, 13 to determine if location affected results. The trajectory analysis covers the probability of a spill reaching the shore, the average time to reach shore, and the minimum time to reach shore (oil not reaching shore within 150 days was defined as not reaching shore) (CEQ, 1974b). The calculations of the model assume that no containment or cleanup measures are taken during the life of the spill.

Table L-1 summarizes the probabilities of spilled oil coming ashore along the Southeast Atlantic Coast. The results are listed for spills occurring at locations 25, 50, 75 and 100 miles from shore on an east-west transect through each EDS center (Figure L-2). The results are in terms of

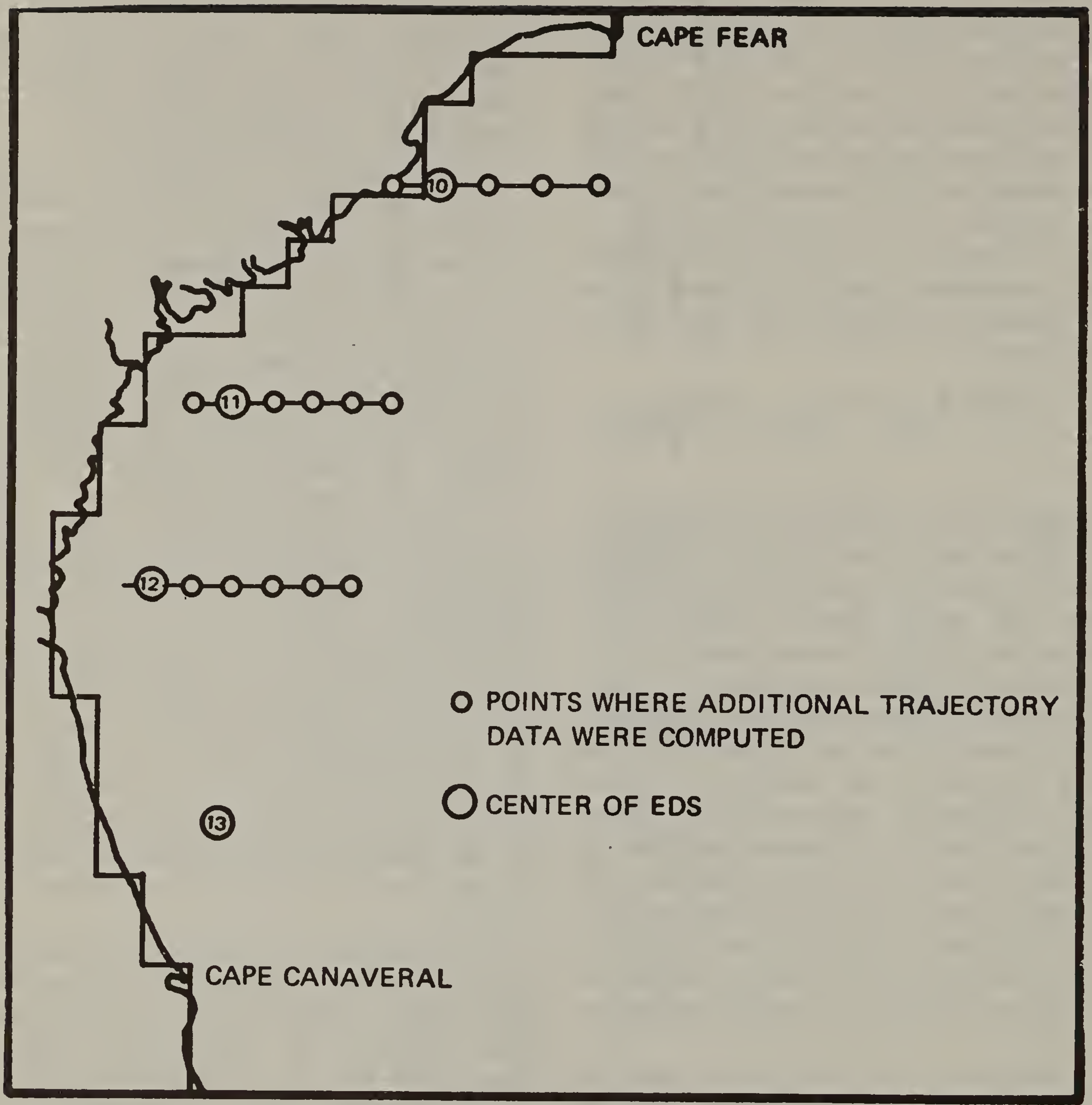

Figure L-1 Points in the Georgia Embayment Region for Which Detailed Trajectories Were Calculated

Source: The Massachusetts Institute of Technology Department of Ocean Engineering.

TABLE L-1

Probabilities of Oil Spills Coming Ashore from Hypothetical Spill Sites in the Atlantic Ocean

Shore point	Season[1]	Distance from shore						Center of EDS
		10 miles east	25 miles east	50 miles east	75 miles east	100 miles east	125 miles east	
Cape Romain, S.C.	Spring	-	95	65	Near 0	-	-	95 (EDS 10)
	Autumn	-	Near 0	Near 0	Near 0	-	-	Near 0 (EDS 10)
Savannah	Spring	-	95-100	95	80	20	-	95-100 (EDS 11)
	Autumn	-	20	5	Near 0	Near 0	-	5 (EDS 11)
Fernandina Beach, Fla.	Spring	-	95	55	20	0-5	-	90 (EDS 12)
	Winter	-	15	10	Near 0	Near 0	-	15 (EDS 12)
Daytona Beach, Fla.	Summer	-	-	-	-	-	-	50 (EDS 13)
	Autumn	-	-	-	-	-	-	Near 0 (EDS 13)

- Computer model not run at this point.

[1]Two seasons are listed for each area. In the first season, oil spilled has the highest probability of reaching shore; in the second season, oil spilled has the lowest probability. Probabilities are intermediate in the unlisted seasons.

Source: CEQ, 1974b.

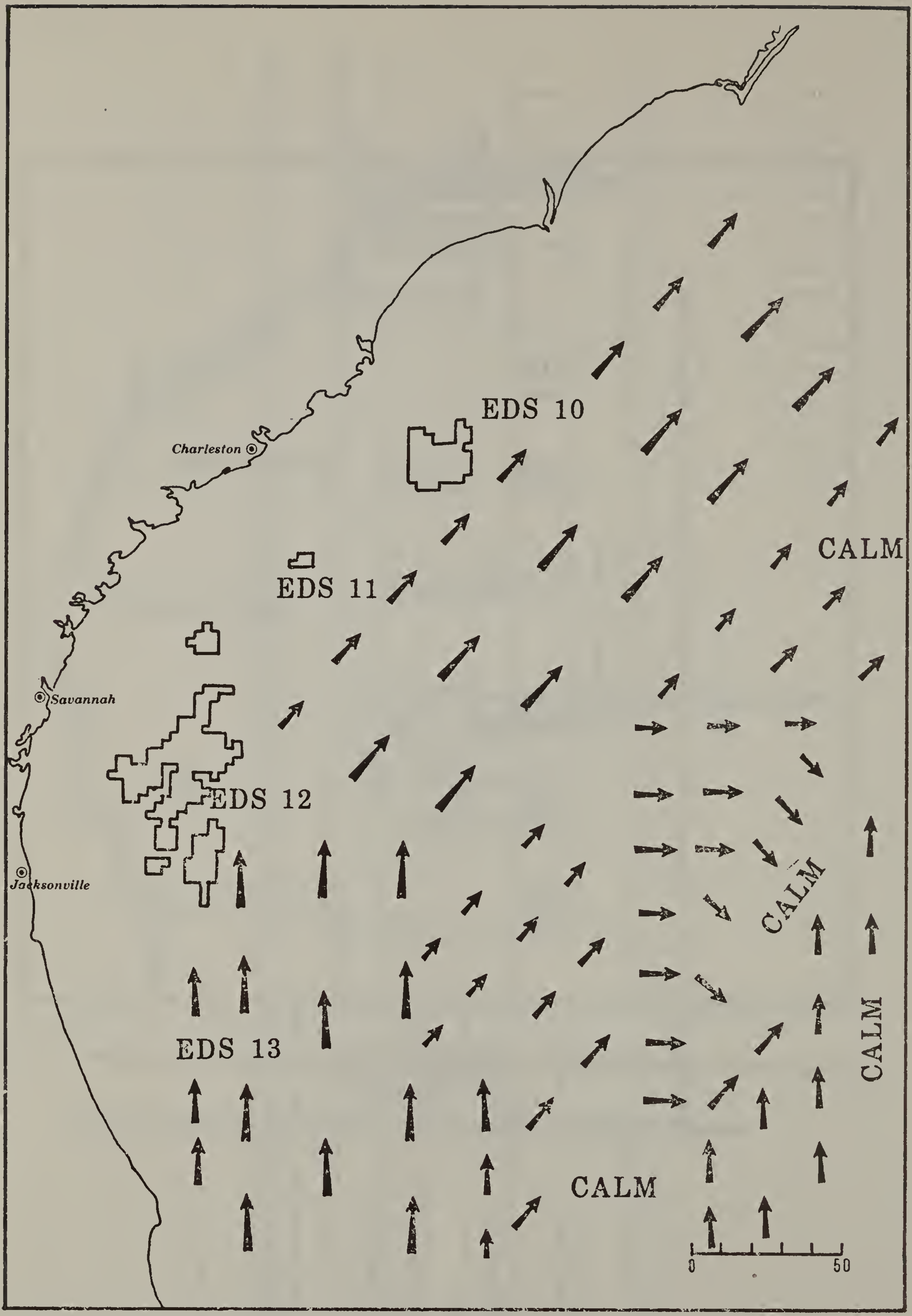

FIGURE L-2 HYPOTHETICAL EASTCOAST DRILL SITES (EDS'S) AND HYPOTHESIZED CURRENT PATTERN FOR GEORGIA EMBAYMENT REGION. (CEQ, 1974A)

the percentage of the time that a spill would beach during the ''best'' and ''worst'' seasons (CEQ, 1974b). ''Spills reaching the shore from the Georgia Embayment sites (EDS 10 to 12) appear very sensitive to distance from shore (see Table L-1). Probabilities drop markedly as the distance from shore increases. Spills nearer shore (within 25 miles) have a high probability of coming ashore—at the sample drilling sites, spring and summer probabilities are over 90%. Even 50 miles from the coast, chances are higher than 50% that a spring or summer spill will reach the coast. Most summer spills from EDS 12 would come ashore near St. Augustine, Fla., or southeastern Georgia. Spills at EDS 10 would beach at Cape Romain or elsewhere in South Carolina.

Beach time is generally shorter for the Georgia Embayment sites than for other areas. The minimum time to shore for a spill in the spring at EDS 10 is 5 days; at EDS 12 the minimum is 20 days.''

Appendix M

An Oilspill Risk Analysis for the South Atlantic Outer Continental Shelf Lease Area

ABSTRACT

An oilspill risk analysis was conducted to determine relative environmental hazards of developing oil in different regions of the South Atlantic Outer Continental Shelf lease area. The study analyzed probability of spill occurrence, likely path of pollutants from spills, and locations in space and time of recreational and biological resources likely to be vulnerable, paying particular attention to "worst-case" conditions. These results are combined to yield estimates of the overall oilspill risk associated with development of the lease area.

INTRODUCTION

The Federal Government has proposed to lease 1,280,966 acres of Outer Continental Shelf (OCS) lands off the South Atlantic coast for oil and gas development. Estimated recoverable petroleum resources for the proposed 225 tract sale area range from 280 million to 1 billion barrels. Contingent upon actual discovery of this quantity of oil, production is expected to span a period of about 25 years.

Oilspills clearly represent one of the major concerns associated with offshore oil and gas development in the South Atlantic. An important fact that stands out when one attempts to evaluate the significance of accidental oil spillage for this, or any proposed lease area, is that the problem is fundamentally probabilistic. A great deal of uncertainty exists, for example, concerning the number and size of spills that might occur during the course of development, as well as the wind and current conditions that would exist and give direction to the oil slick at the specific times spills do occur. While some of the uncertainty reflects incomplete and imperfect data, considerable uncertainty is simply inherent in the problem.

In view of the inability to predict with certainty future oilspill impacts, it is important to consider the range of possible impacts that could accompany oil and gas development, paying particular attention to "worse-case" conditions. It is equally important, however, in attempting to maintain perspective on the problem, to associate these potential impacts with quantitative estimates of the probability of their occurrence.

This report summarizes results of an oilspill risk analysis conducted for the South Atlantic OCS lease sale. The study had the objective of determining relative risks associated with oil and gas development in different regions of the proposed lease area and was undertaken to facilitate final selection of tracts to be offered for sale. The analysis was conducted in three more or less independent parts corresponding to different aspects of the overall problem. The first part dealt with the probability of spill occurrence, the second with likely spill trajectories for the times and places spills might occur, and the third part with the spatial and temporal location of specific biological and recreational resources thought to be vulnerable to oilspills. Results of the individual parts of the analysis were then combined to give estimates of the overall oilspill risk associated with oil and gas development in the lease area.

Much of the data and information used in the analysis were compiled by the Bureau of Land Management in the course of preparing the environmental statement for the South Atlantic sale. These results, then, represent synthesis and analysis of existing information rather than presentation of new material.

We would like to express special appreciation to John Meier of the Bureau of Land Management for his assistance in gathering the necessary data and information for the study.

Methods

A detailed mathematical description of the models used in this analysis is given in a forthcoming Geological Survey publication by Smith, Slack, and R. K. Davis. The present discussion focuses on the conceptual framework of the models, and on data sources and limiting assumptions.

Spill Frequency Estimates

Statistical distributions for estimating probabilities of oilspill occurrence were taken from Devanney and Stewart (1974) and Stewart (1975). In addition to the fundamental assumption that realistic estimates of future spill frequency can be based on past OCS experience, use of these distributions requires the further, specific assumptions that spills occur independently of each other (that is as a Poisson process) and that accident rate is dependent on volume of oil produced and handled.

Spill frequency estimates were calculated separately for eight subdivisions of the proposed lease area (Fig. 1) based on estimated petroleum resources for individual prospects within those areas (U.S. Geological Survey, proprietary data).

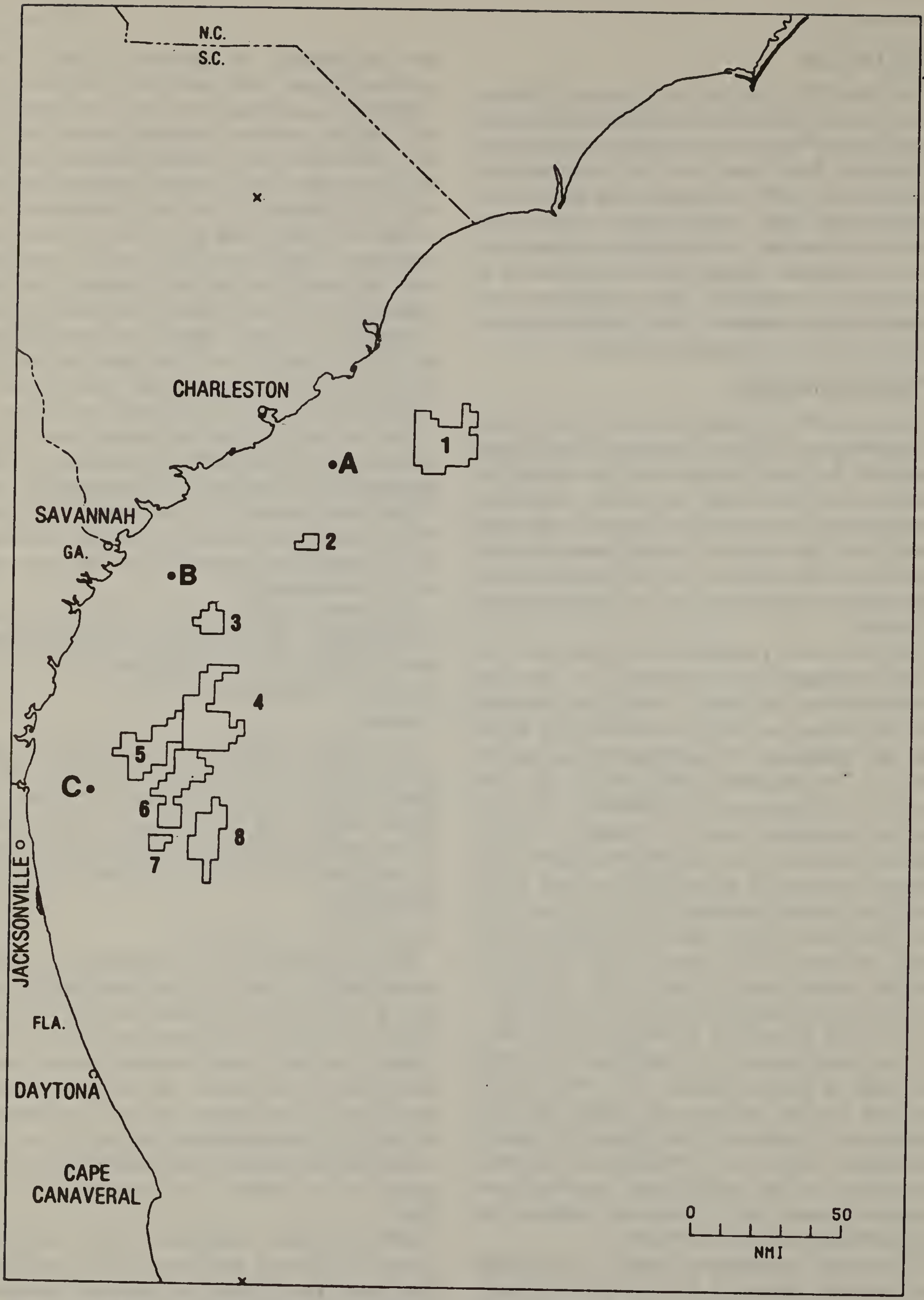

Figure 1.--Map of the South Atlantic Outer Continental Shelf showing subdivision of the lease area and hypothetical transportation routes.

Use of the Devanney and Stewart distributions permitted separate estimates of platform, pipeline, and tanker spill frequency which could then be combined to compare the two alternative modes of transport of crude to shore. Spill frequency estimates were further categorized for spills between 50 and 1,000 bbls, and greater than 1,000 bbls in size. The size grouping is somewhat arbitrary but, as discussed below, is very important in considering the significance of weathering in reducing oilspill impacts.

Oilspill Trajectory Simulations

An oilspill trajectory model was constructed and used to analyze movements of hypothetical oil slicks on a digital map of the South Atlantic coast between lat. 28° and 35′ N. and between about long. 76° 20′ W. and the Atlantic coast. The coordinate system for this area was established with a grid size of 1 nautical mile. Monthly surface current velocity fields were provided by Bureau of Land Management staff and were based on drift-bottle data (Bumpus, 1973). Short-term patterns in wind variability were characterized with a probability matrix for successive 3-hour velocity transitions (first order Markov process). Wind transition matrices were evaluated from U.S. Weather Service records from the Jacksonville, Fla. and Charleston, S.C. weather stations (7 years continuous record each) and were established separately for four seasons.

Trajectories of 500 hypothetical oilspills were simulated in Monte Carlo fashion for spill sites within each of the eight subdivisions of the lease area and along three hypothetical transportation routes, under wind and current conditions for the four seasons, yielding a total of 22,000 trajectories. Surface transport of the oil slick for each spill was simulated as a series of straightline displacements of a point in space, each representing the joint influence of wind and current on the slick for a 3-hour period. Wind transition probability matrices were randomly sampled each period for a new wind speed and direction, and the current velocity was updated as the spill changed location in the velocity field. The wind-drift factor was taken to be 0.035 with a drift angle of 20°.

The final product of trajectory model runs consists of a large number of simulated oilspill trajectories or pathways which collectively reflect both the general trend and variability of winds and currents (see Figs. 4 through 7), and which can be summarized in statistical terms. It should be emphasized that these trajectories represent only hypothetical pathways for the transport of oilslicks and do not involve any consideration of cleanup, dispersion, or weathering processes which would determine the quantity and quality of oil that may eventually come in contact with biological populations or other important resources. The significance of dispersion and weathering in mitigating oilspill impacts is discussed in more detail below.

Locations of Biological and Recreational Resources

The locations of 19 categories of biological and recreational resources were digitized in the same coordinate system as that used in trajectory simulations (See Appendix, Figs. A-1 to A-19). The monthly sensitivity of these resources (For example, spawning or migration period) was also recorded. Resource groups were as follows:

1. Sandy beaches
2. Recreation areas
3. Wildlife refuges
4. Historical sites
5. Marsh and wetlands
6. Turbid water zone
7. Brown pelican rookeries
8. Coastal or pelagic bird rookeries
9. Bald eagle nesting sites
10. Dusky seaside sparrow habitat
11. Arctic peregrine falcon migration routes
12. White, brown, and pink shrimp
13. Royal red shrimp
14. Commercial fishing grounds
15. Sport fishing areas
16. Commercial scallop grounds
17. Crabs and oysters
18. Bay scallops
19. Sea turtle nesting sites

RESULTS AND DISCUSSION

Spill Frequency Estimates

The probability distribution on the frequency of oilspills greater than 1,000 bbls in size during the production life of the proposed lease area is given in Figure 2. Probabilities apply to the total of production platform spills and pipeline spills assuming transport of the total product to shore via pipeline. Although transport by pipeline is the preferred method, tanker or barge transport is considered a possibility, at least for the early years of production. The corresponding frequency distribution for the total of platform and tanker spills is presented in figure 3 for comparison. Means of the distributions in Figures 2 and 3 are indicated with arrows.

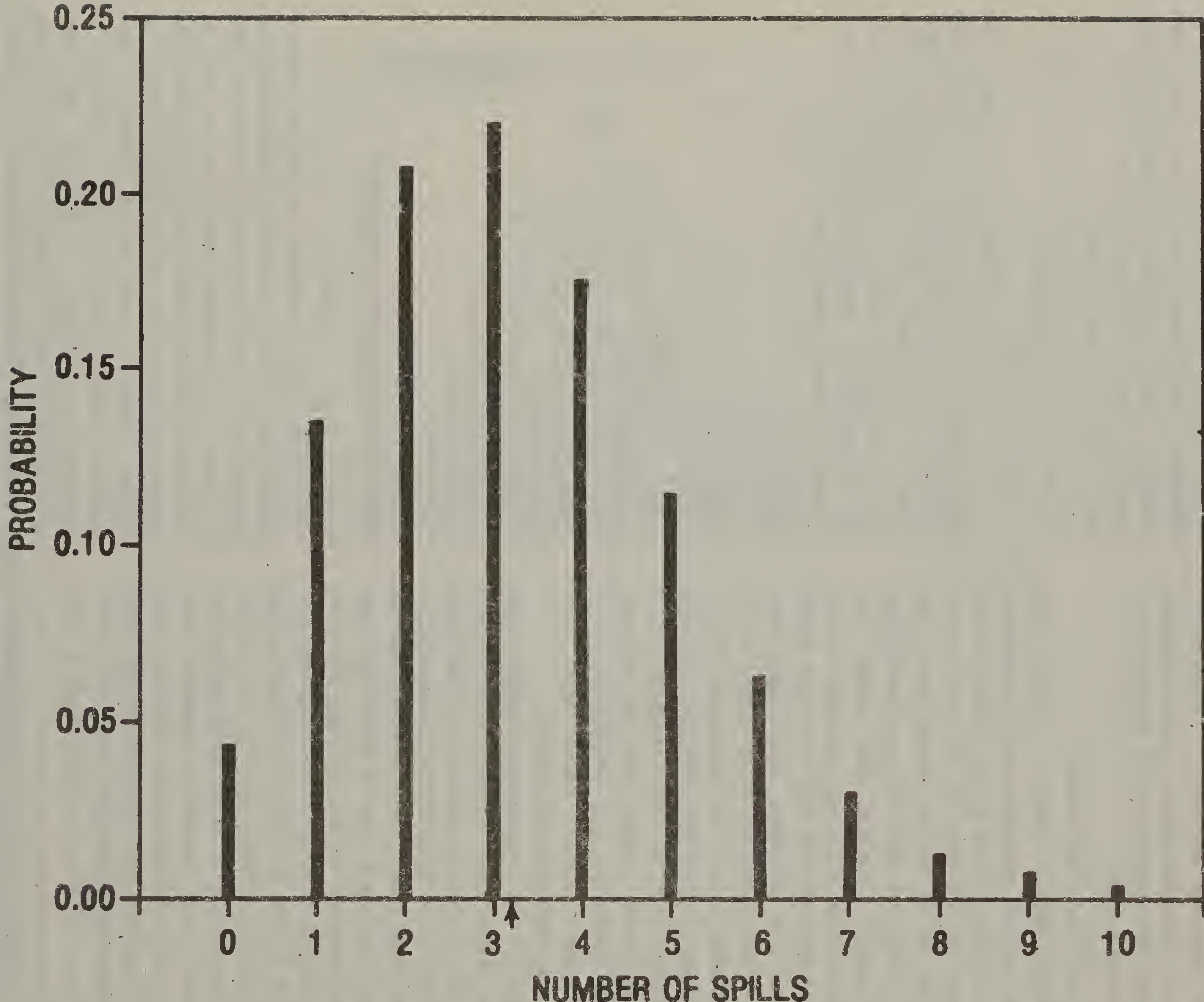

Figure 2.--Spill frequency distribution for platform and pipeline spills greater than 1,000 bbls during the production life of the lease area.

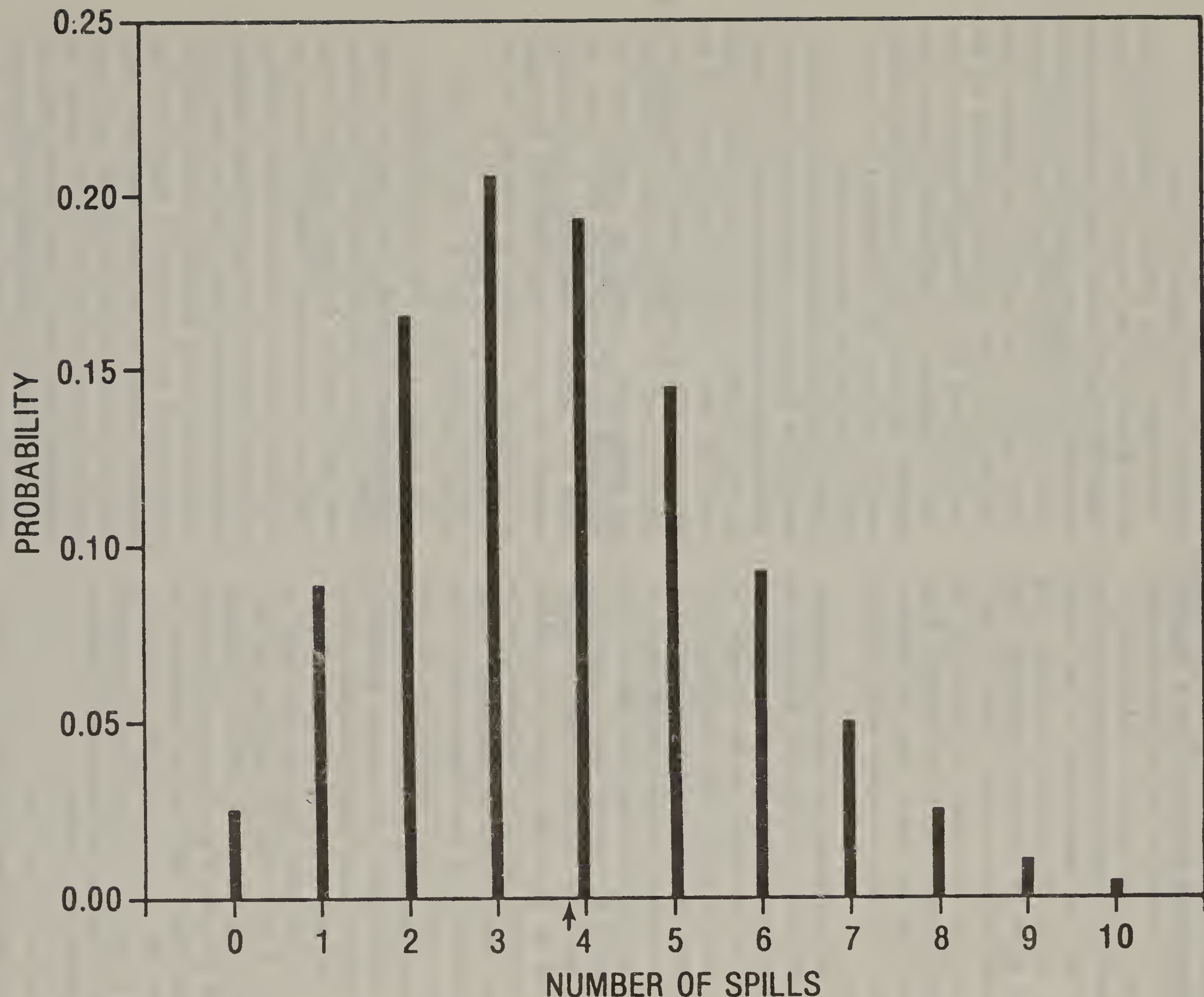

Figure 3.--Spill frequency distribution for platform and tanker spills greater than 1,000 bbls during the production life of the lease area.

In the absence of refinery construction in the South Atlantic region, it is expected that any crude oil transported by pipeline from the lease area to storage facilities on shore (e.g., Charleston, Savannah, or Jacksonville) would be subsequently carried by tanker from these terminals to existing refineries elsewhere. Thus it should be noted that in addition to the spill risk associated with production and transport to shore (Fig. 2), there would be a further increment of risk associated with this tanker traffic in and out of southern ports. An estimate of tanker spill frequency based on estimated production from South Atlantic oilfields is given in table 1. Only a fraction of this risk, however, applies to the South Atlantic coastal region, the remainder being distributed along the tanker routes to refineries and within the estuaries and ports where terminals are located.

One of the advantages of making predictions about oilspill frequency in the form of a probability distribution is that such data give not only an estimate of the most likely number of spills that would be expected to occur but some measure of the uncertainty that exists about that prediction. Figure 2, for example, indicated that the expected number of spills greater than 1,000 bbls is about 3 spills (mean of 3.2), but that there is only about 22-percent probability that there would be exactly 3 spills and an 85-percent chance the number would be anywhere from 1 to 5 spills (obtained by summing the probabilities over that range). Noting that the probability of zero oilspills greater than 1,000 bbls is only about 4 percent, one can conclude that the probability of at least one spill (i.e., sum of the probabilities for one and greater) is about 96 percent. Again, these probabilities apply to the sum of platform and pipeline spills over the field life of the entire proposed lease area. A breakdown of these data for platform, pipeline, and tanker spills appears in table 1A. Expected frequencies for spills in the size range of 50-1,000 bbls and less than 50 bbls over the production life of the total area are given in tables 1B and 1C. Available sources do not provide for a meaningful separation of pipeline and platform spill statistics for spills smaller than 1,000 bbls.

Recent Trends in Spill Statistics

All of the above figures are subject, of course, to the validity of earlier stated assumptions, the most important of these being that accident rates per unit production of future South Atlantic fields would be the same as those observed to date in other areas. One might question this assumption either from the point of view that safety records might be expected to improve with time, or from the standpoint that accident rates are not transferable to a newly opened OCS area.

With regard to the question of improvement in accident rates, recent statistics from U.S. Coast Guard files show no clear trend in spillage rates for production platforms and pipelines during the period 1971-75. Spill frequency estimates given above (table 1) for platform and pipeline spills were based on Gulf of Mexico statistics for the years 1971 and 1972, for which the accident rate was 3.6 incidents per million bbls produced and handled (all sizes). The corresponding accident rates for the years 1973-1975 were 3.9, 4.2 and 3.2 incidents per million bbls respectively.

There is evidence, however, of recent improvement in the incidence of tanker spills. Frequency estimates given above for tanker spills were based on world statistics for the years 1969-72 (spills over 1,000 bbls) and U.S. Coast Guard data for the years 1971-72 (spills under 1,000 bbls) for which the overall accident rate was 0.45 incidents per million bbls handled (all sizes). The corresponding rate for the years 1973-74 was only about 0.07 incidents per million bbls, although some of the apparent improvement is due simply to a change in the method of estimating volumes of crude handled in U.S. ports.

Oilspill Trajectories

The results of trajectory model runs consist of a large number of hypothetical oilspill trajectories (22,000) which collectively reflect both the general trend and variability of winds and currents and which can be described in statistical terms. Ten trajectories based on wind and current conditions for each of the four seasons have been randomly selected as examples from a total of 2,000 trajectories released from location 3 near the center of the lease area and are shown in Figures 4-7. The patterns evident in trajectory simulations vary with the seasons. In the winter, the trajectories tend to wander northward. In the spring, the trajectories move more quickly toward shore in various directions. In the summer, the trajectories generally travel north and south parallel to the shore. In the autumn, the trajectories tend to move southward quickly toward shore. These pat-

Table 1.--Oilspill frequency estimates by potential source for the South Atlantic lease area based on distributions of Devanney and Stewart, 1974.

	Expected number	Probability of at least one spill
A. Spills >1,000 bbl		
Platforms	1.5	0.78
Pipelines	1.7	.81
Tankers	2.2	.89
Platforms and pipelines	3.2	.96
Platforms and tankers	3.8	.98
B. Spills 50-1,000 bbl		
Platforms and pipelines	32	>0.99
Tankers	16	> .99
C. Spills 0-50 bbl (mean size approx = 1 bbl)		
Platforms and pipelines	2,338	>0.99
Tankers	277	> .99

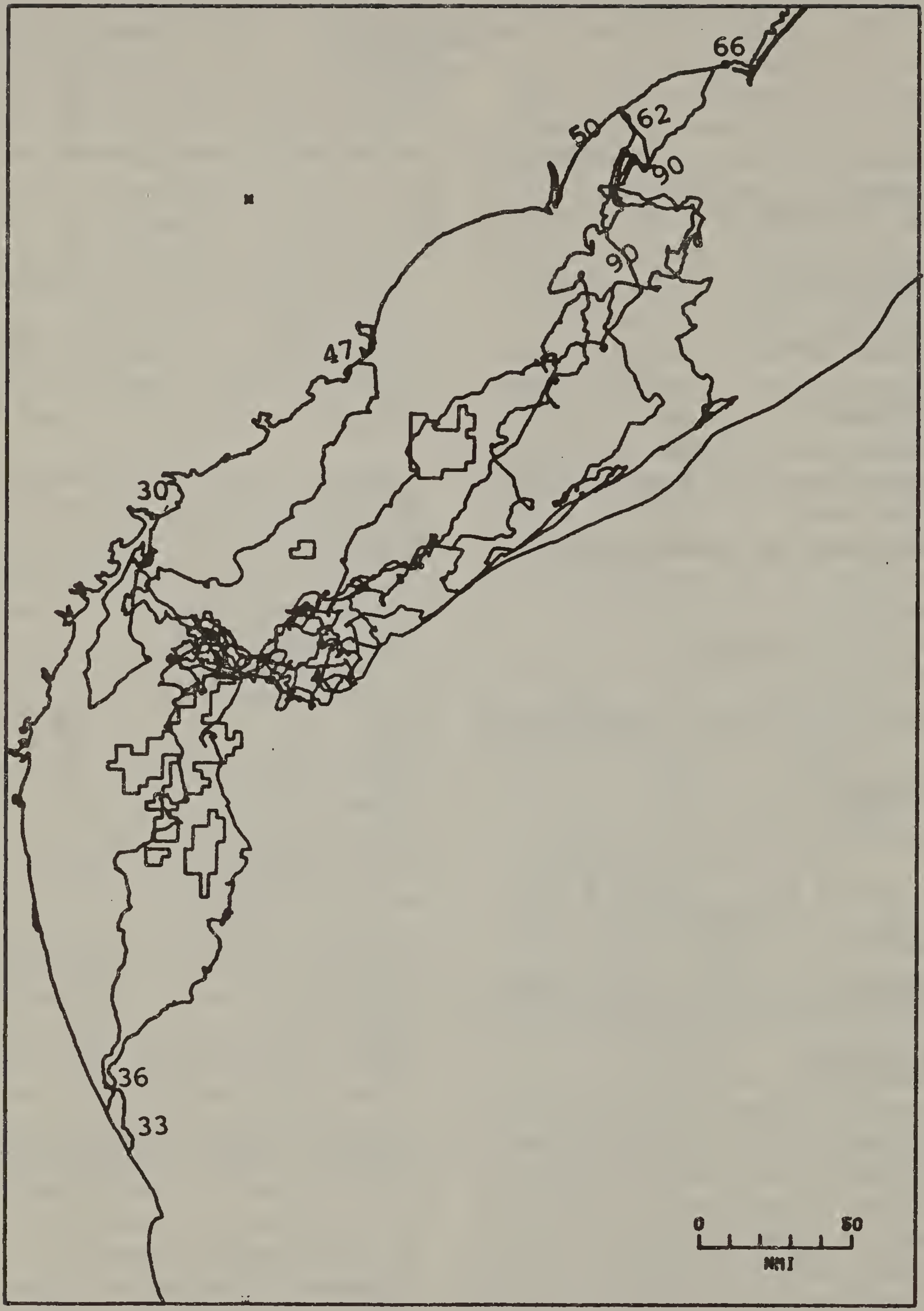

Figure 4.--Example oilspill trajectory results for a spill site near the center of the proposed lease area: winter conditions. Number on trajectory reaching the coast gives time to land in days.

Figure 5.--Example oilspill trajectory results for a spill site near the center of the proposed lease area: spring conditions. Number on trajectory reaching the coast gives time to land in days.

Figure 6.--Example oilspill trajectory results for a spill site near the center of the proposed lease area: summer conditions. Number on trajectory reaching the coast gives time to land in days.

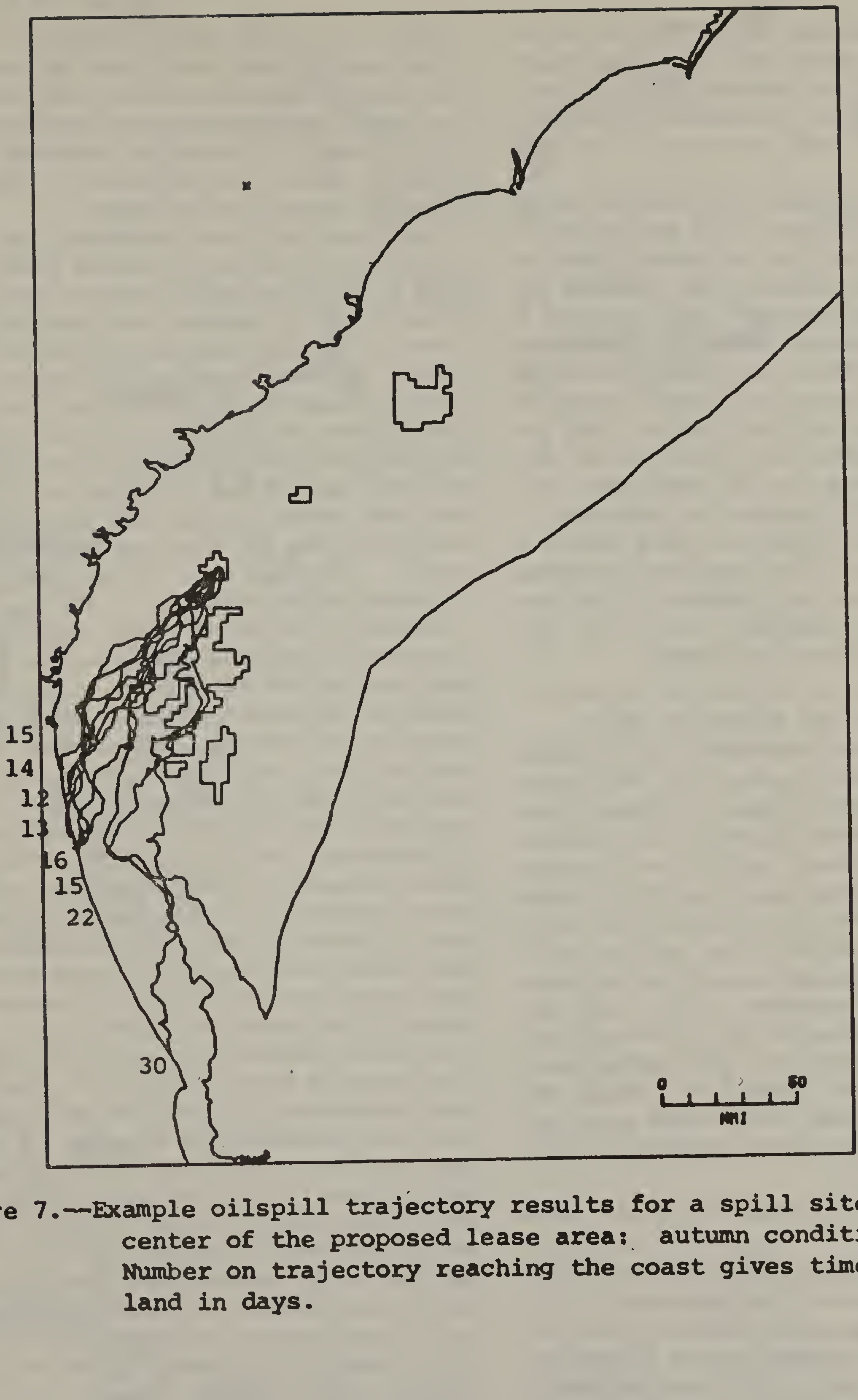

Figure 7.--Example oilspill trajectory results for a spill site near the center of the proposed lease area: autumn conditions. Number on trajectory reaching the coast gives time to land in days.

terns largely hold true for the other seven sites except that the northern sites have more northerly tendencies and the southern sites have more southerly tendencies. The east-west trajectories in figures 5 and 7 show the effects of the Gulf Stream.

The spatial disposition of the trajectory simulations is shown in figure 8. The final location of each trajectory was recorded and the results for each spill site (weighted by the estimated spill frequencies) were averaged. Thus, according to figure 8, 44 percent of the spill trajected ashore on the Florida coast, 3 percent on the Georgia coast, about 12 percent on South Carolina, and about 23 percent on North Carolina. Three percent of the trajectories were left at sea; i.e., after 90 days of tracking they had neither beached or left the map. The tendency for trajectories to travel parallel to the coast, as seen in figure 4, is reflected in figure 8. The highest rates of landings occurred northeast and southwest of the lease area. The coast immediately west of the lease area received relatively few landings.

Oilspill Trajectories in Relation to Biological Resources and Recreation Areas

Oilspill trajectory simulations were conducted keeping track of the frequency with which trajectories intersected the locations of biological and recreational resources. Trajectories were recorded as impacting a resource only in cases where the resource was listed as being vulnerable to oilspills in the month the impact took place. Table 2 gives the probability of impact on each of the 19 categories of biological resources and recreation areas for a spill originating at the 11 spill sites within the lease area (see Fig. 1). As one would expect, the likelihood that a given spill trajectory would beach at the location of a specific land based resource during critical seasons is generally smaller than the 84-percent probability of coming ashore anywhere.

Estimates of Weathering Rates and Slick Dispersion

It must be emphasized that up to this point the analysis has dealt only with trajectories for the transport of surface oil by winds and currents and has not involved any consideration of dispersion or weathering processes which would progressively reduce the quantity of oil contained in the slick as it traveled towards shore. The probabilities given in table 2, therefore, represent a worst-case analysis in the sense that some fraction of the spills occurring more than 50 miles off shore in the lease area would be expected to deteriorate to the point of insignificance before reaching land. Some attempt at quantifying weathering and dispersive effects and accounting for them in probability estimates is thus in order.

One important factor determining the significance of weathering in reducing oilspill impacts is the time required for spills to reach land. Times to land for simulated trajectories, in fact, covered a very wide range, and it is therefore particularly important to consider this factor in interpreting results of the spill trajectory analysis. Table 3 shows the mean number of days at sea for trajectories which reached the coast within 90 days from the spill sites. The mean time to land from the production areas tend to vary quite widely both from site to site and from season to season reflecting the various trajectory "corridors" discussed above.

Included in the list of factors which would determine the potency of spills at the time of impact would be spill size, of course, as well as the quality or composition of the oil, since lighter weight crudes evaporate at a much more rapid rate than those with a large proportion of high molecular weight hydrocarbons. This latter factor being hard to predict in advance, the significance of weathering is difficult to quantify despite its obvious importance in interpreting these results. Some suggestion as to South Atlantic oil quality may be contained in test well results from Sable Island in the North Atlantic; oil sample gravities there ranged from 36° to 41° API, indicating a medium to light weight crude (Smith, 1975).

The most important conclusion to be reached from the data in table 3 is that times to shore for most spills will be so long that they will no longer exist as an identifiable slick but rather will have fragmented into a large number of discrete particles or "blobs" by the time any oil arrives on shore. Observations by Jeffrey (1973) of actual spills in the North Atlantic indicate breakup of the slick can be expected within about 4 days, and that the particles of residual oil typically consist of spongy emulsions of oil of widely varying sizes. Moreover, it is generally agreed that large fractions of the original volume of oil will evaporate in the first few days of weathering and that further loss to the atmosphere occurs at a very slow rate. Data from Nelson (1958) for crude

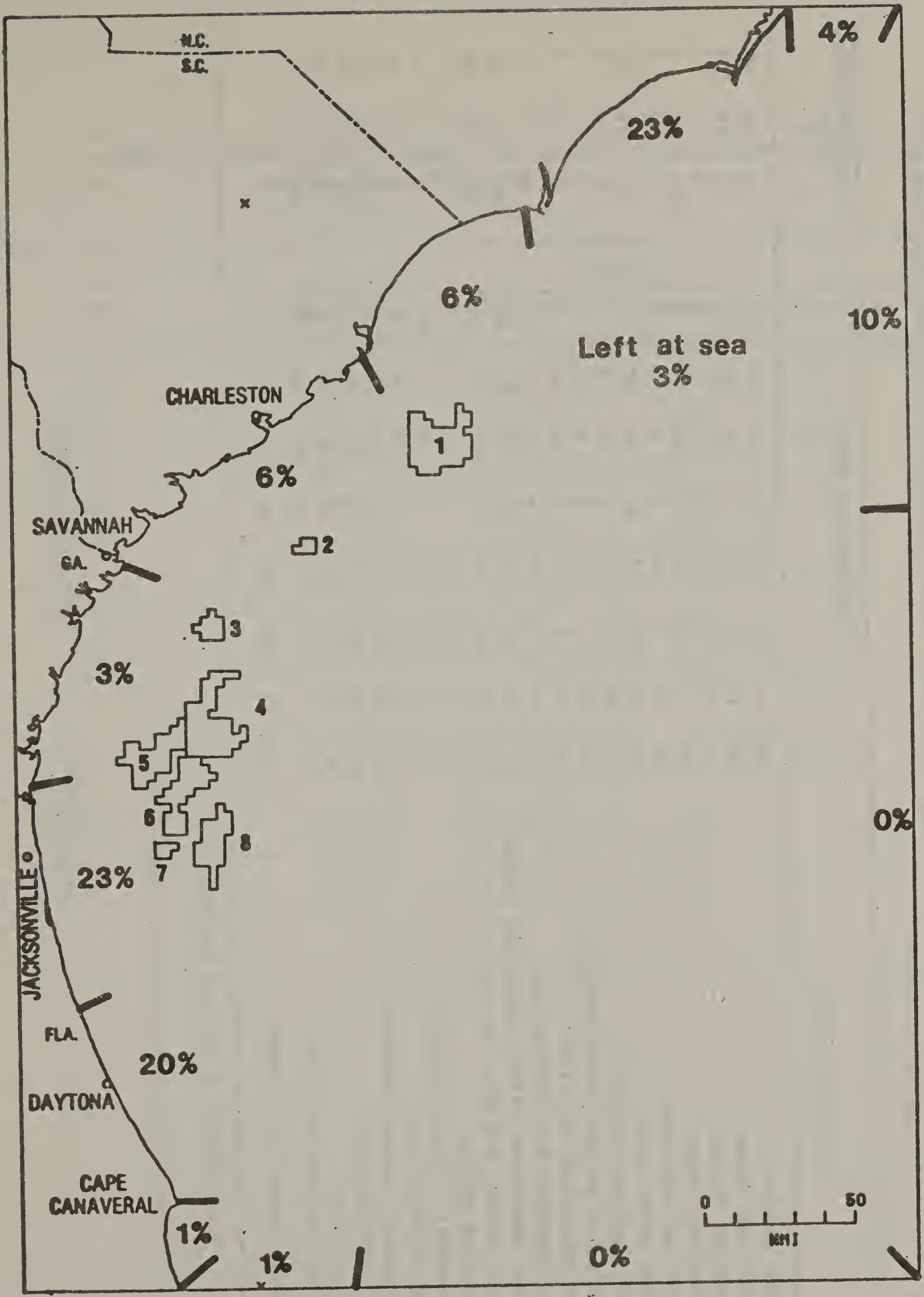

Figure 8.--Probability that if an oilspill occurs in the South Atlantic lease area, it will reach a particular geographic location.

Table 2.--Percent probabilities that an oilspill occurring at potential production areas in the South Atlantic lease area would impact important biological resources and recreation areas.

Resources Group	Production Area 1	2	3	4	5	6	7	8	Transportation Route A	B	C
Sandy beaches	69	73	84	84	88	89	93	90	79	86	97
Recreation areas	16	14	15	16	17	16	13	12	12	15	21
Wildlife refuges	1	2	4	2	2	2	2	2	4	4	5
Historical sites	19	17	10	11	10	10	7	7	16	6	4
Marsh and wetlands	6	7	5	4	4	4	3	4	7	8	3
Turbid water zone	19	27	28	23	26	26	27	24	32	31	30
Brown pelican rookeries	*	*	1	1	1	2	2	1	*	1	2
Coastal or pelagic bird rookeries	4	4	3	3	2	2	2	2	3	2	2
Bald eagle nesting sites	*	*	*	*	*	*	*	*	*	*	*
Dusky seaside sparrow habitat	*	*	*	*	*	*	*	*	*	*	*
Arctic peregrine falcon migration routes	57	60	73	75	77	79	83	82	63	71	88
White, brown, and pink shrimp	31	31	34	30	31	27	27	25	31	33	35
Royal red shrimp	*	*	1	1	*	1	1	2	*	*	*
Commercial fishing grounds	g	g	g	94	g	g	g	97	g	g	g
Sport fishing area	2	1	1	2	2	2	1	3	1	1	*
Commercial scallop grounds	32	22	16	19	15	15	11	13	19	8	7
Crabs and oysters	34	37	27	21	21	18	14	16	49	28	10
Bay scallops	4	3	2	2	2	1	*	*	3	1	*
Sea turtle nesting sites	35	38	40	37	39	36	34	34	40	38	37
Overall probability ashore	69	73	86	86	90	91	95	93			

* Less than 0.5 percent probability.

g Greater than 99.5 percent probability.

Table 3.--Mean time to shore (in days) for spills originating on the South Atlantic OCS.

	Site	Season			
		Winter	Spring	Summer	Autumn
Production Areas	1	55	24	38	39
	2	58	24	28	29
	3	51	26	24	20
	4	48	33	31	17
	5	46	29	27	13
	6	40	35	30	13
	7	29	36	25	10
	8	38	38	31	13
Transportation Routes	A	57	14	22	24
	B	49	12	12	15
	C	19	22	10	7

oil of API gravity 40°, for example, indicate about 50 percent of the original spill volume would be lost to evaporation.

Thus for oilspills in the South Atlantic lease area it would appear that an important consideration is the extent to which fragments of the slick are dispersed by the time they reach shore. Using lateral dispersion coefficients from Csanady (1974) estimates of slick dispersion were made for various travel times and for two spill sizes, 1,000 bbls and 50 bbls, assuming 50 percent loss of the original volume by evaporation. The resulting distribution of oil along an assumed straight shoreline is given in Figure 9. It is important to note that the profiles will flatten considerably as the coastline becomes more irregular. In any case, it appears that residual oil from a single spill as small as 50 bbls would not be easily detected on the beach after 30 days at sea.

COMBINED ANALYSIS: SPILL FREQUENCY ESTIMATES AND OILSPILL TRAJECTORIES

It is worth briefly summarizing some of the important points to be drawn from the results presented thus far. Data in table 1 indicate that although more than 2,300 oilspill incidents would be expected during the course of oil production in the South Atlantic, only a very few (and possibly none at all) are likely to exceed 1,000 bbls. Furthermore, consideration of travel time to shore (table 3), evaporation rates, and rates of slick dispersion (Fig. 9) leads to the conclusion that an individual spill would need to be as large as 1,000 bbls in size in order to have significant ecological impact. The probabilities in table 2 give the chances that if a major spill occurs in the lease area it would come ashore and hit any of various important resources; these probabilities are discussed in combination with the frequency estimates for major oilspills in paragraphs that follow.

Further consideration should be given first, however, to the significance of small scale, chronic spillage which, according to table 1, might amount to about 100 accidents annually over a 25-year period. The question arises whether a large number of small spills occurring during the course of oil and gas development in the lease area would have significant cumulative impact in the form, for example, of tar and other petroleum residues washing up on South Altantic beaches. In attempting to answer this question, results of the spill trajectory model runs were used to estimate the distribution of petroleum residues along the South Atlantic coast that would result from the 2,370 spills smaller than 1000 bbls projected during the production life of the area. Results of this analysis are shown on a map of the area in Figure 10. The mean size of spills in the range of 0-1000 is estimated to be about 3 bbls. Concentrations of petroleum residues given in Figure 10 are based on the assumption of a 50 percent loss of the original spill volume to evaporation and the worst case assumption of no success in spill containment efforts. It has been estimated (Offshore Oil Task Group, 1973) that offshore containment efforts might be successful in seas of less than 5 feet although it is questionable whether the equipment would be deployed for spills smaller than 50 bbls.

According to Figure 10, total quantities of petroleum residues that would be expected to come ashore over the 25-year production life of the area as a result of chronic, small-scale spillage range from a high of 500-1,000 grams per meter of beach along the Florida coast and places in North Carolina to less than 100 grams per meter near the Georgia-South Carolina border. It is helpful to compare the concentrations in Figure 10 with actual measurements of tar and oil residues on Florida beaches reported by Dennis (1959, 1974) and believed to result from tanker traffic and natural seeps. He found rates of fouling in the Miami area during recent years to be about 700 grams per meter per year, an annual accumulation, in other words, that is of the same order of magnitude as that projected to result from the entire 25 years of OCS operations.

Returning to consideration of major spills (i.e., greater than 1000 bbls), the data presented in table 2 represent only a partial solution to the problem of assessing oilspill risks to important resources. The overall oilspill risk posed by oil and gas development in the proposed sale area must be assessed as a joint function of the probability that spills will occur in the course of development as well as the likelihood that spills will follow certain trajectories. Thus, the data in table 2 must be combined with the spill frequency estimates presented in Figures 2 and 3 above to obtain a total probability distribution for impacts on specific resources.

Despite the intuitive logic of simply multiplying the probabilities in Figure 2 by those in table 2,

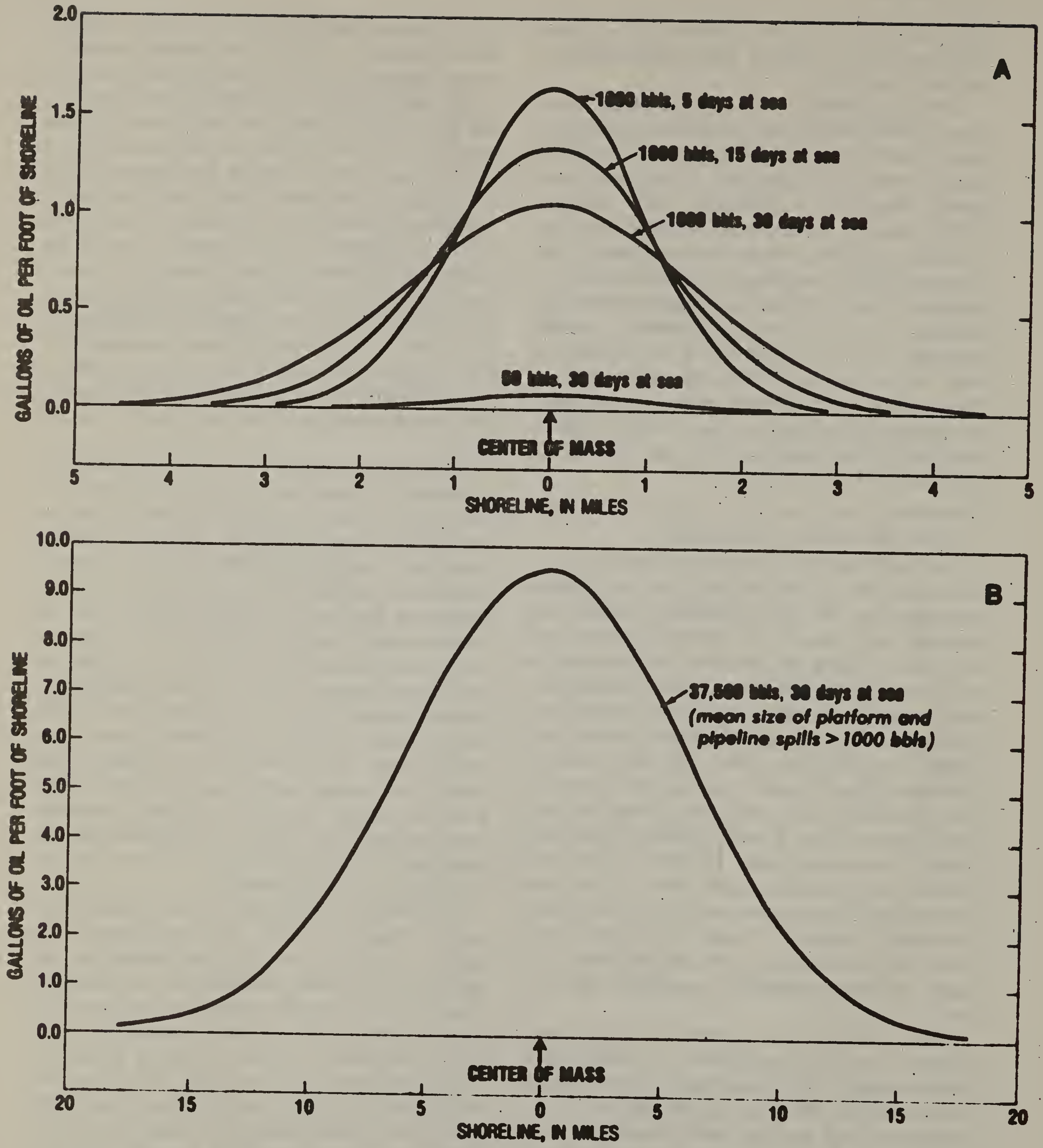

Figure 9.--Density of beached residual oil along idealized shoreline for various travel times and initial sizes.

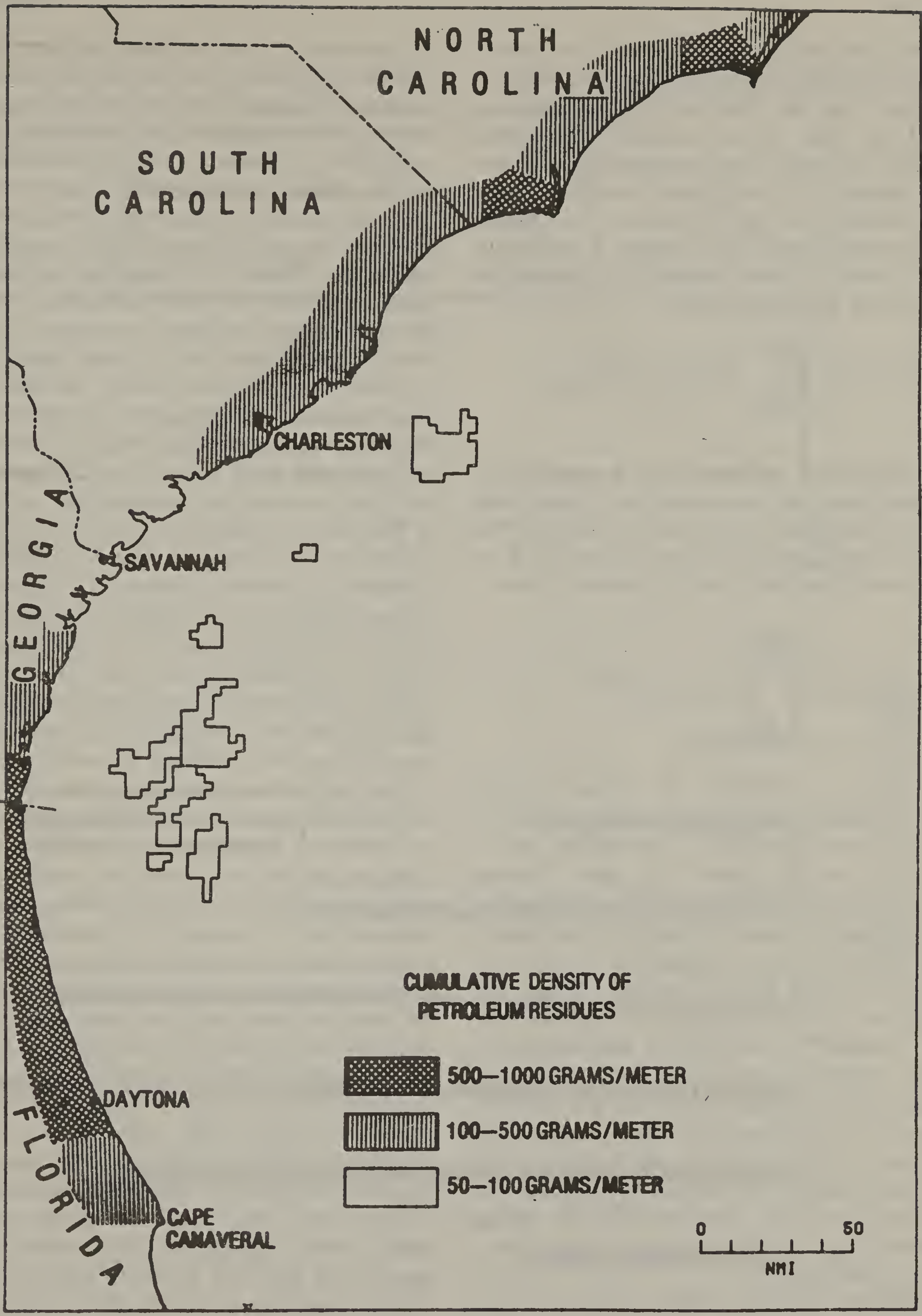

Figure 10.--Projected cumulative distribution of petroleum residues on South Atlantic beaches resulting from small scale, chronic spillage during the production life of the lease area. Estimated densities do not include existing background levels resulting from tanker washings and natural seeps.

the correct computation of the overall or "total" probability is in fact somewhat more complicated. This results from the fact that the probabilities presented in table 2 are actually conditional probabilities and refer to the probabilities of impacts on resources "conditioned" on the chance of spills occurring in the first place. The overall probability that oilspills will impact a particular resource exactly k times during the production life of the area, P(k), is given by

$$P(k) = \sum_{n=k}^{\infty} P(k|n)\ P(n)$$

where P(k/n) is the probability of k impacts on the resource given the occurrence of n spills, and P(n) is the probability of n spills occurring. The conditional probability P(k/n) can be assumed to be distributed binominally and is given by

$$P(k|n) = \binom{n}{k} p^{k} (1-p)^{n-k}$$

where p is the probability of impact on the resource given the occurrence of a spill, (table 2).

The combined probability distribution calculated in the above manner for spills coming ashore is presented in Figure 11. The distribution is based on spill frequency estimates from Figure 2 and therefore refers to impacts from all spills originating as 1,000 bbls or greater during the production life of the total lease area and assumes pipeline transport to Jacksonville and Savannah. Figure 11 indicates that there is an 8-percent probability that no oilspills greater than 1,000 bbls will occur and come ashore in the course of oil production in the proposed lease area. The chances are therefore, 92 percent that at least one such spill would occur and come ashore during the production life of the area (sum of the probabilities of 1 and greater).

Probability distributions similar to Figure 11 can be developed and likewise interpreted for each of the 19 categories of biological resources and recreation areas. Probabilities of at least one major spill occurring during the production life of the area and impacting the various resource groups are given in table 4. The data have been calculated separately for two alternative methods of transport of the oil from the lease area, by pipeline and tanker, and are further separated according to assumptions concerning transportation routes. It is emphasized that probability estimates refer only to chances that oil in some form or another from a spill originating larger than 1,000 bbls will come in contact with some portion of a resource thought to be potentially vulnerable. The mitigating effects of weathering processes and clean-up efforts are only indirectly reflected in the probabilities in table 4 by virtue of the fact that estimates apply only to large spills. Figure 9 provides a rough description of the likely effects of evaporation and dispersion on spills of various sizes as a function of time. To this must be added the likelihood of at least some, and perhaps considerable, success in containing oil in the course of the days or weeks separating the occurrence of a spill on the OCS and its arrival on shore.

There is a natural tendency for impact probabilities in table 4 to be larger for resources which occupy a large portion of the shoreline or continental shelf than for those that are restricted to small, localized areas. The significance of an oilspill impact on a biological resource, however, may be somewhat inversely related to areal extent of the habitat since recovery from spill damages would likely depend on the fraction of the population effected. Consequently, in order to give perspective to the risk values in table 4, a fifth column of data is provided showing the size of each of the 19 resources in relation to the estimated mean size of spills larger than 1,000 bbls. Onshore resources are compared with spill size on the basis of linear measure (estimated mean spill diameter after 30 days of weathering is 25 mi; see Fig. 9) and offshore resources are compared on the basis of areal extent (estimated mean spill area is 490 mi^2). Thus, after 30 days at sea, a 37,500 bbl spill would be dispersed over an area equal to only about 2 percent of commerical fishing grounds in the region, but upon reaching the coast, would deposit oil over a length of shore equal to at least one tenth the length of exposed marshes and wetlands in the area. Tides and nearshore currents would be expected to further spread the beached oil to some extent. Fortunately, the chances a major spill will hit marshes and wetlands is estimated to be less than 10 percent.

In general, resource groups showing the highest impact probabilities in table 4 are beaches and recreation areas as well as commercial fish and

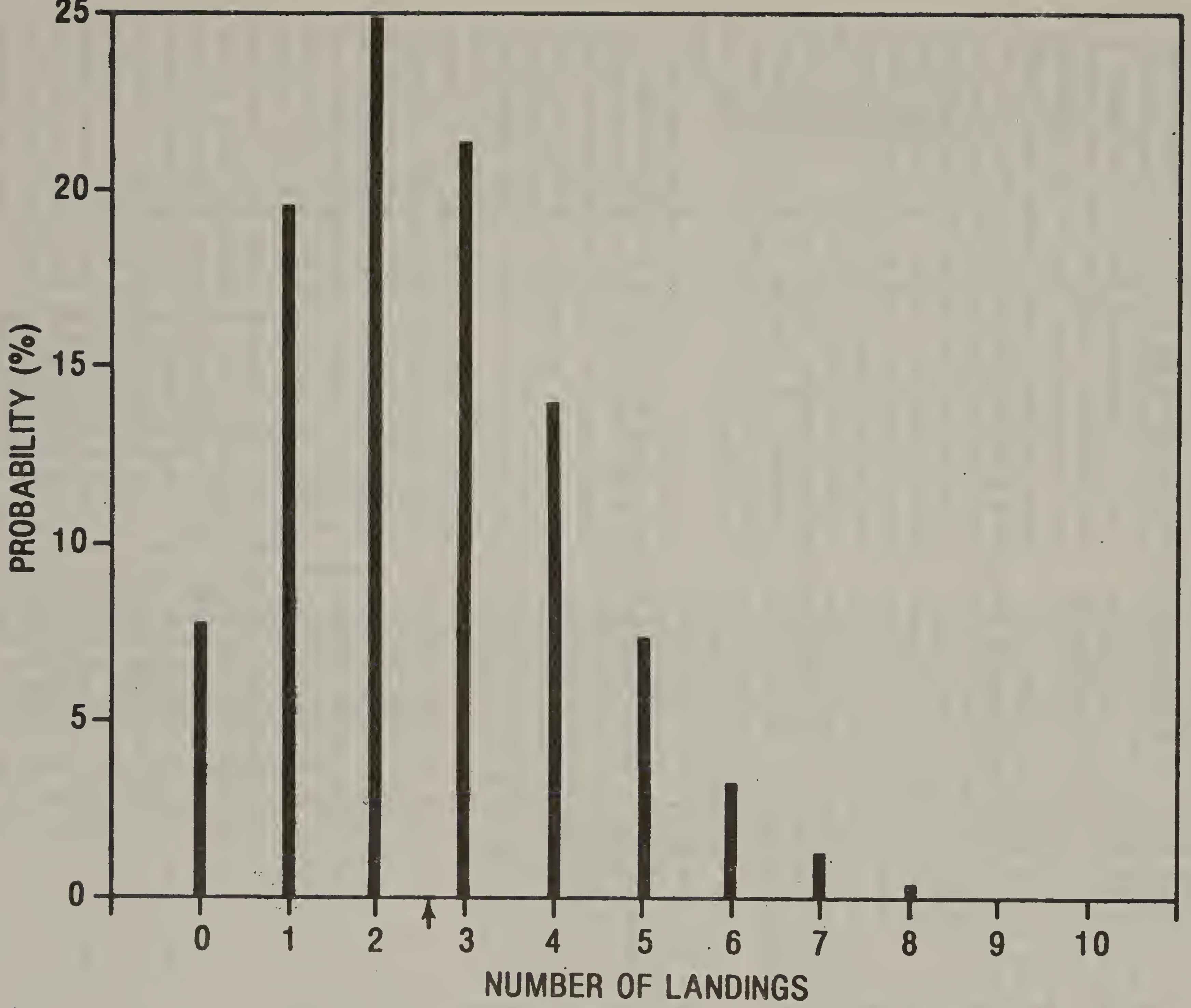

Figure 11.--Probability distribution on frequency of landings for oilspills greater than 1,000 bbls over the production life of the South Atlantic lease area. Based on pipeline transport to Jacksonville and Savannah.

Table 4.--Probabilities of one or more spills greater than 1,000 bbls occurring and impacting biological resources and recreational areas in the South Atlantic area over the production life of the entire lease area. Also, the size of a major spill in relation to the extent of exposed resource.

Probability (percent)

	Based on pipeline transport to Jacksonville and Savannah	Based on pipeline transport to Charleston and Savannah	Based on tanker transport to Jacksonville and Savannah	Based on tanker transport to Charleston and Savannah	Ratio of mean spill size to extent of exposed resource ǂ
Probability of coming ashore	93	92	96	95	.04
Beaches	93	92	95	95	.05
Recreation areas (State and Federal)	40	39	45	43	.24
Wildlife refuges	8	8	9	9	.53
Historical sites	29	32	33	33	1.0
Marsh and wetlands	15	16	17	14	.10
Areas of high sedimentation rate	55	55	61	62	.12
Brown pelican rookeries	3	2	4	3	3.33
Coastal or pelagic bird rookeries	8	8	9	9	.37
Bald eagle nesting sites	*	*	*	*	10.00
Dusky seaside sparrow habitat	*	*	*	*	25.00
Arctic peregrine falcon migration routes	89	89	93	93	.04
White, brown, and pink shrimp	62	62	69	69	.07
Royal red shrimp	2	2	2	2	2.5
Commercial fishing grounds	95	95	97	97	.02
Sport fishing area	4	5	5	5	.71
Commercial scallop grounds	43	44	47	49	.22
Crabs and oysters	53	58	59	65	.06
Bay scallops	6	7	7	7	.53
Sea turtle nesting sites	69	69	75	75	.05

* Less than 0.5 percent.

ǂ Onshore resources compared on the basis of length and offshore resources on the offshore resources on thé basis of area (see text).

shellfish grounds, while those showing relatively low risk include the habitats of most of the non-commercial fish and wildlife populations. The category, sandy beaches, is not discriminative of level of recreation usage or commercial importance and, thus would stand some further elaboration. According to Figure 8, which gives the geographical distribution of trajectory probability, the chances are 43 percent that if a spill occurs in the lease area, it will come ashore on the Florida coast north of Cape Canaveral, a stretch of coast that includes Jacksonville, Ft. Lauderdale, and Daytona Beach. Combining this probability with the spill frequency distribution (Figure 2 and equations 1 and 2) results in an estimate of 74 percent for the chances that at least one major spill would come ashore in this region sometime during the producing life of South Atlantic oilfields. By contrast, the corresponding probability estimate for one or more spills impacting the entire Georgia coast is only 9 percent over the field life. As with the estimates in table 4, these figures do not directly account for the mitigating effects of weathering or containment efforts and are based on the worst-case assumption that future accident rates will remain constant.

The high impact probabilities for commercial fish and shellfish areas in table 4, as in the case of beaches and recreation areas, reflect the fact that the extensive areas along the South Atlantic coast are involved in commercial fishing of one sort or another. The nature of effects of oil in fish and shellfish areas, however, is much less clear than is the problem of oil on beaches. Past experience with oilspills in shellfish areas has ranged from reportedly severe and lasting effects in the case of the West Falmouth spill, when toxic components of the oil were quickly churned into near-shore sediments (Blumer, 1970), to much more modest effects following the "Torrey Canyon" spill when more time was available for weathering before impact (Smith, 1968). There may be some significance to the fact that crab, oyster, and shrimp harvesting areas in the South Atlantic region are largely coincident with an area of relatively high sedimentation rate (see Appendix Figs. A-6, A-12, A-17) whereas commercial scallop grounds lie outside this region (see Appendix Figs. A-16 and A-18). The hazards of spilled oil to commercial fishing in deeper water offshore probably lies more in the possible oiling of nets and gear and possible effects on buoyant eggs of such species as menhaden, rather than in mortality of adult fish.

Biological resources showing the lowest impact probabilities in table 4 include a number of ecologically important but non-commercially sought fish and wildlife populations. Critical habitats of vulnerable bird populations, including known nesting sites and rookeries of the brown pelican, bald eagle and a variety of pelagic sea birds, as well as the remaining habitat of the endangered dusky seaside sparrow, all show impact probabilities of less than 10 percent for major spills over the oil producing life of the area.

Two wildlife categories that do show high impact probabilities, sea turtle nesting sites and the peregrine falcon coastal migration route, do so because lack of detailed information on critical elements of the habitat necessitated including in the analysis all possible locations of the organisms. Thus, along with the high probability estimates, it should be noted (table 4) that a 37,500 bbl spill would be expected to impinge on less than 5 percent of the potential habitat of these two populations.

Finally it is important that the distinction between the probabilities given in table 2 and those in table 4 be very clear. The data given in table 2 refer only to the likelihood that spills would follow certain trajectories and have nothing to do with the chances that spills will occur in the first place. The probabilities in table 4, by contrast, reflect both the expected frequency of spill occurrence as well as the likelihood of certain trajectories.

Relative Risks of Leasing in Different Parts of the Lease Area

One objective of the present study is to elucidate the relative risks of petroleum development in different regions of the proposed lease area, information which is necessary in selecting the tracts to be offered for sale. One consideration of importance in comparing the oil spill risk associated with different potential production areas is the value or weight to be assigned to each of the biological and recreational resources, since a given tract will pose proportionally greater risk to some resources than others, depending on location. With respect to offshore fishing areas, for example, tracts well off the coast show the highest probabilities of impact in the event of a

spill (table 2), whereas with respect to resources along the shore, spills occurring in the westernmost subdivisions of the lease area show higher impact probabilities. For purposes of this analysis means of the impact probability distributions for the 17 resource groups will be averaged to give an overall index of risk for each of the subdivisions of the lease area, but it should be noted that this averaging implies to an equal weighting of the resources.

It is extremely important in comparing risk values for the different subdivisions of the lease area to distinguish between two fundamentally different ways of expressing relative risks. One can compare subdivisions of the lease area on the basis of impact probability given the occurrence of a spill using the data in table 2. This is equivalent, in fact, to making the comparison on the basis of risk per unit oil recovery, since the data in table 2 are conditioned on the occurrence of one spill and spill frequency is taken to be a direct function of oil production. Alternatively, one can make the comparison on the basis of total risk by using data computed as in table 4 which combine spill frequency estimates with the probabilities of observing certain trajectories.

The question of which is the most appropriate method of ranking the subdivisions of the lease area with respect to oilspill risk might be answered differently depending on one's perspective. If one is interested in the question of tradeoffs between the benefits of producing oil and the costs of possible spill impacts, then risk per unit oil is clearly of most interest. If one stands to lose a great deal personally in the event of a spill, a loss that is far out of proportion to one's expected gains from oil production, then absolute risk is of most interest.

In table 5, the 8 subdivisions of the lease area are ranked on the basis of risk to the 19 resource categories (equally weighted) using both methods of expressing relative risk. It is clear from table 5 that some of the tracts showing the highest total risk to resources in the South Atlantic, those in subdivisions 1 and 4, for example, are situated so that they actually pose less risk per unit oil production than tracts in several other subdivisions. That is, despite their safer location with respect to important resources and prevailing winds and currents, the expected high level of production in subdivisions 1 and 4, results in a higher overall chance of impacts from these areas. This theory is, of course, wholly dependent on a strong relationship between accident rate and production level.

Table 5. Rank ordering of 8 subdivisions of the South Atlantic lease area on the basis of oil spill risk to biological resources and recreation areas. Numbered subdivisions are shown in the map in Figure 1. and are listed here in order of decreasing risk.

Ranking on the basis of risk per unit oil production	Number of tracts and (area in hectares)	Ranking on the basis of total risk over the estimated production life	Number of tracts and (area in hectares)
3	11 (25,344)	1	51 (117,504)
5	36 (82,944)	4	52 (119,808)
2	5 (11,520)	5	36 (82,944)
6	36 (82,944)	6	36 (82,944)
1	51 (117,504)	3	11 (25,344)
4	52 (119,808)	8	29 (66,816)
7	5 (11,520)	2	5 (11,520)
8	29 (66,816)	7	5 (11,520)

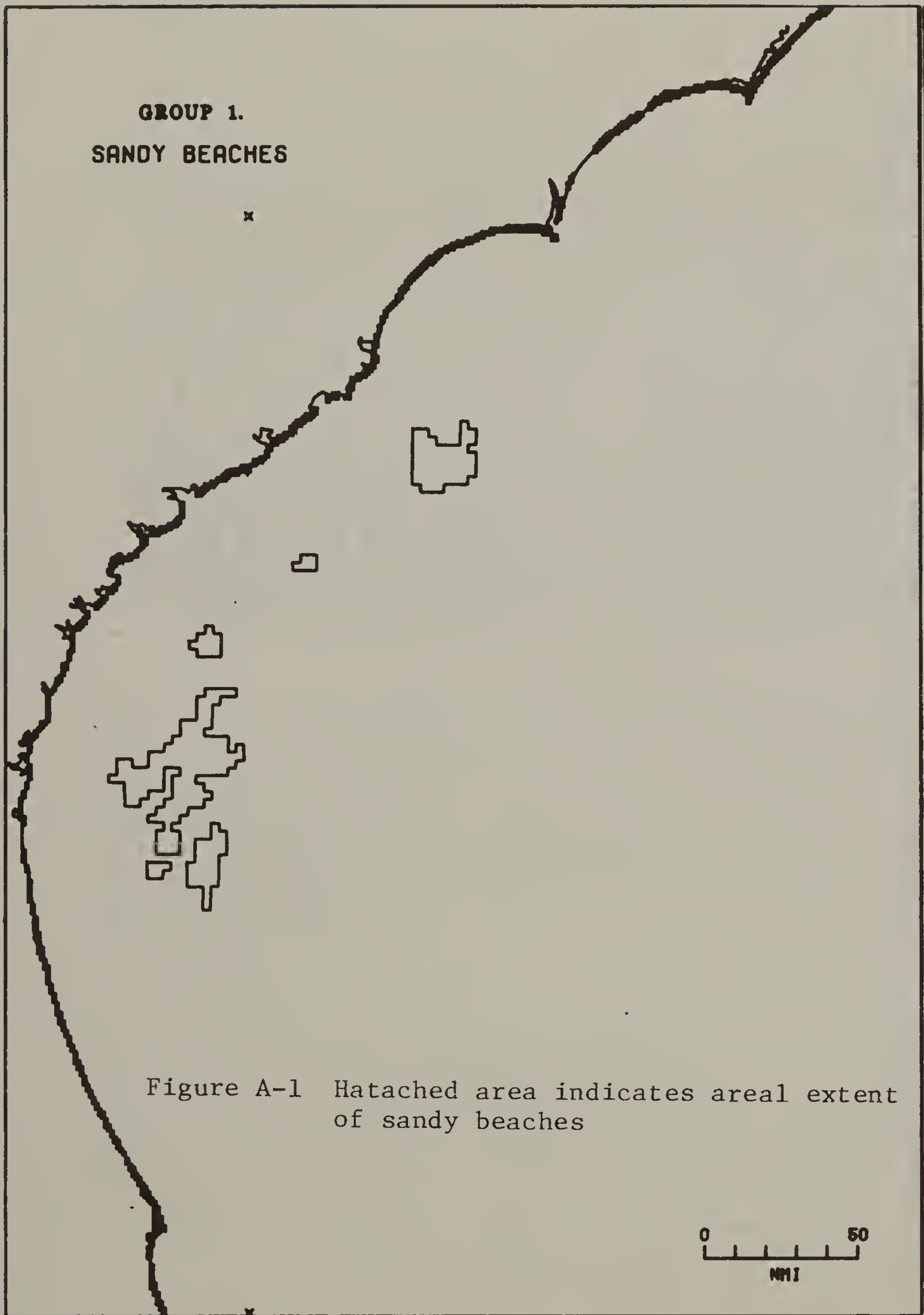

Figure A-1 Hatached area indicates areal extent of sandy beaches

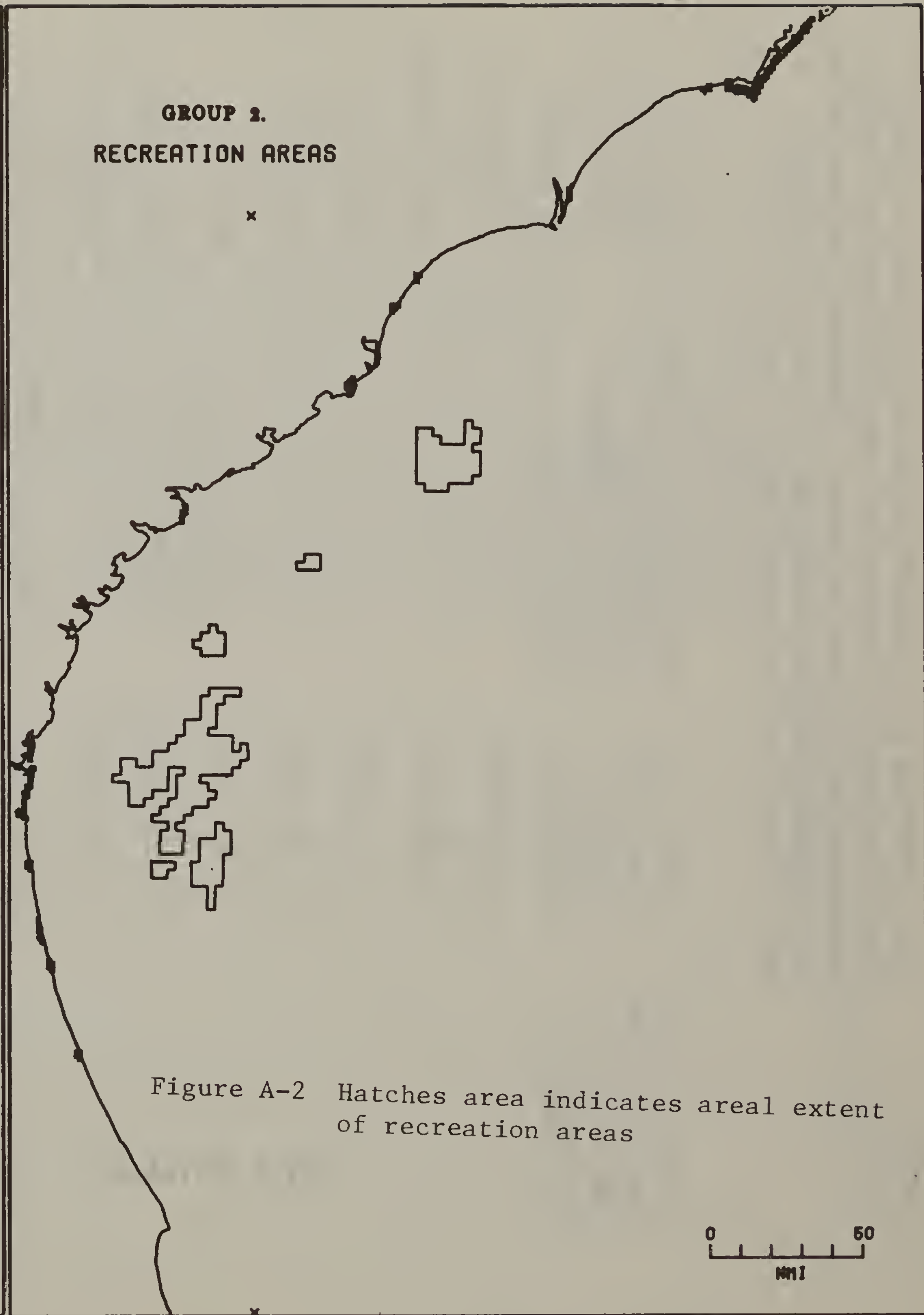

Figure A-2 Hatches area indicates areal extent of recreation areas

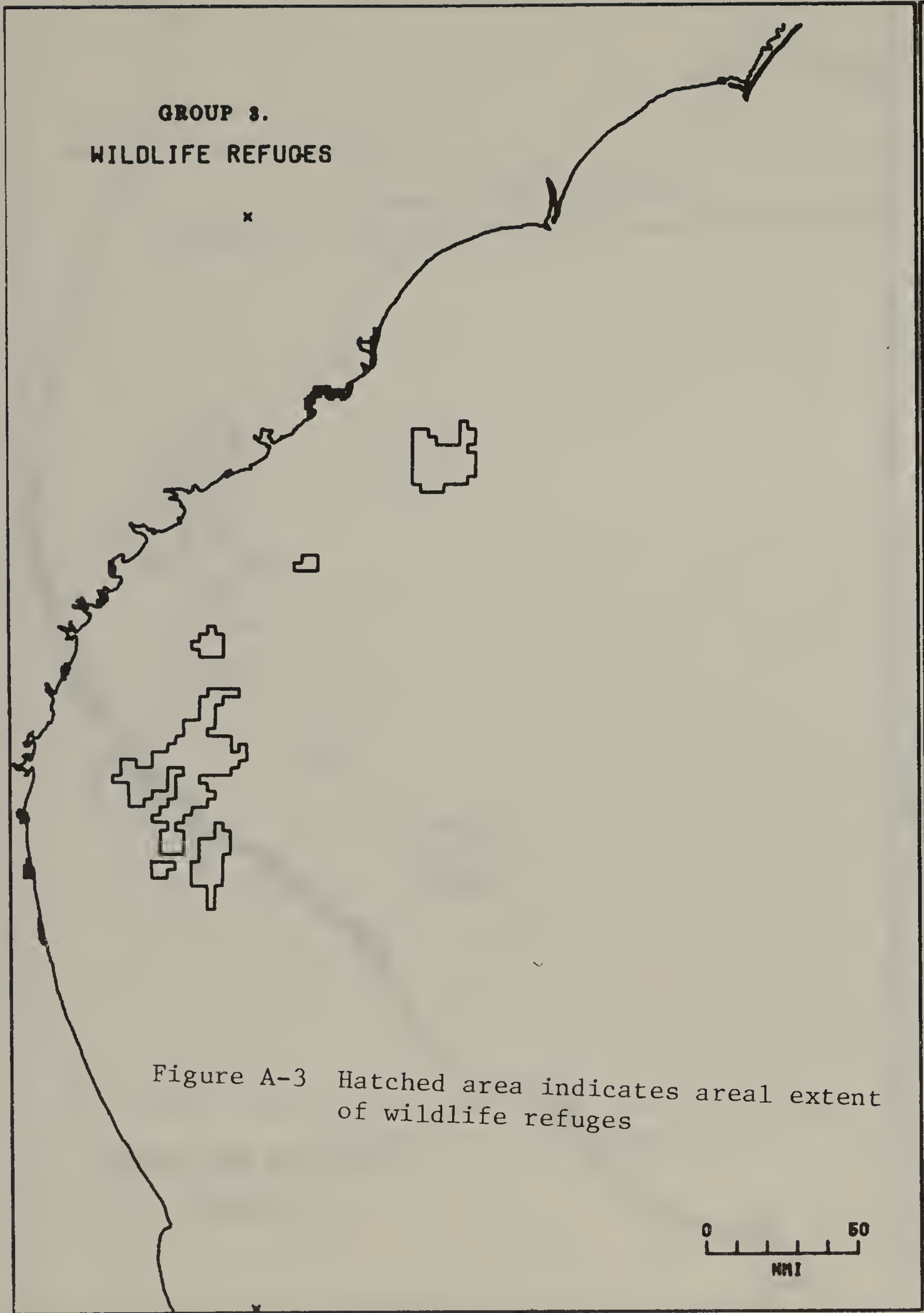

Figure A-3 Hatched area indicates areal extent of wildlife refuges

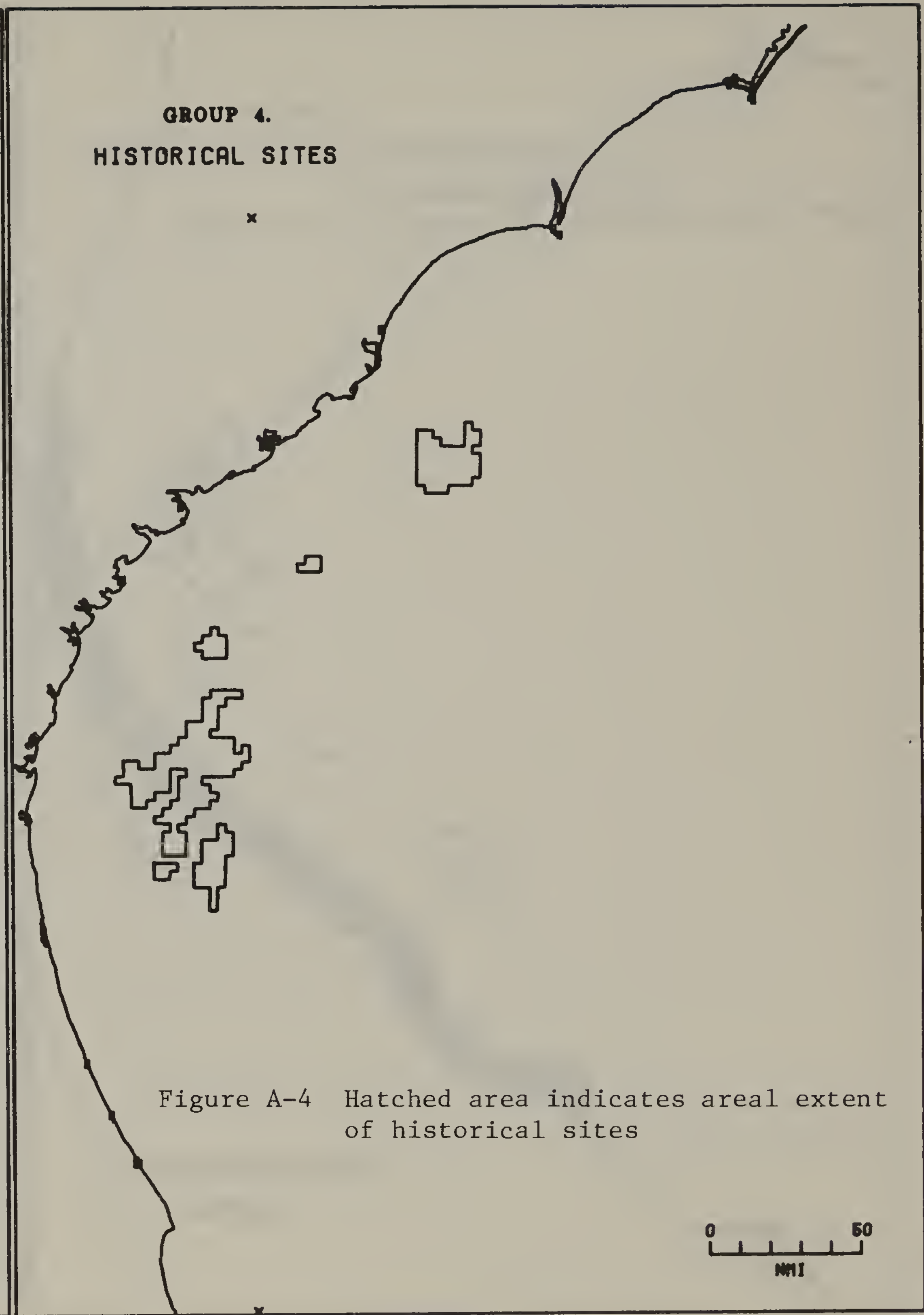

Figure A-4 Hatched area indicates areal extent of historical sites

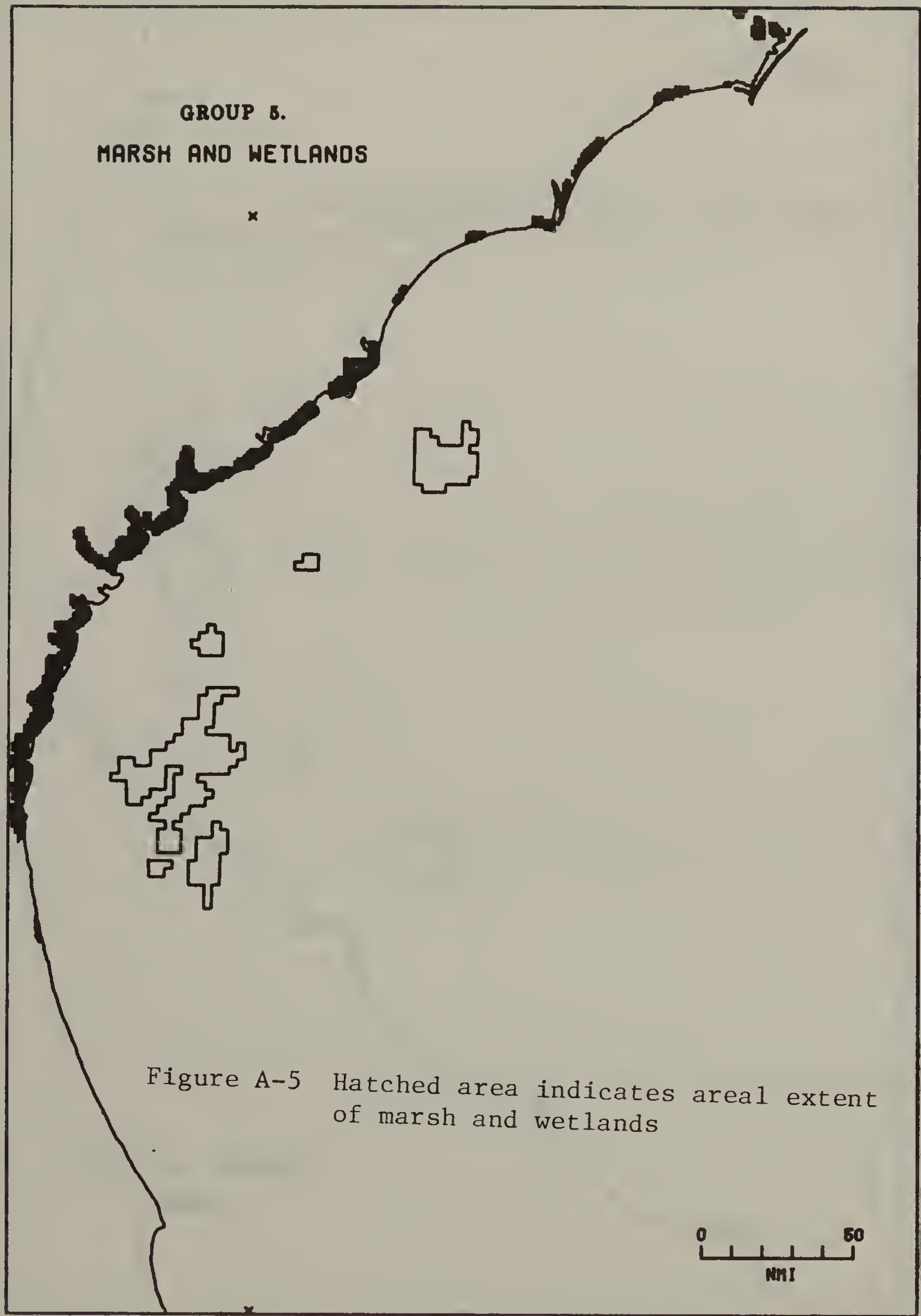

Figure A-5 Hatched area indicates areal extent of marsh and wetlands

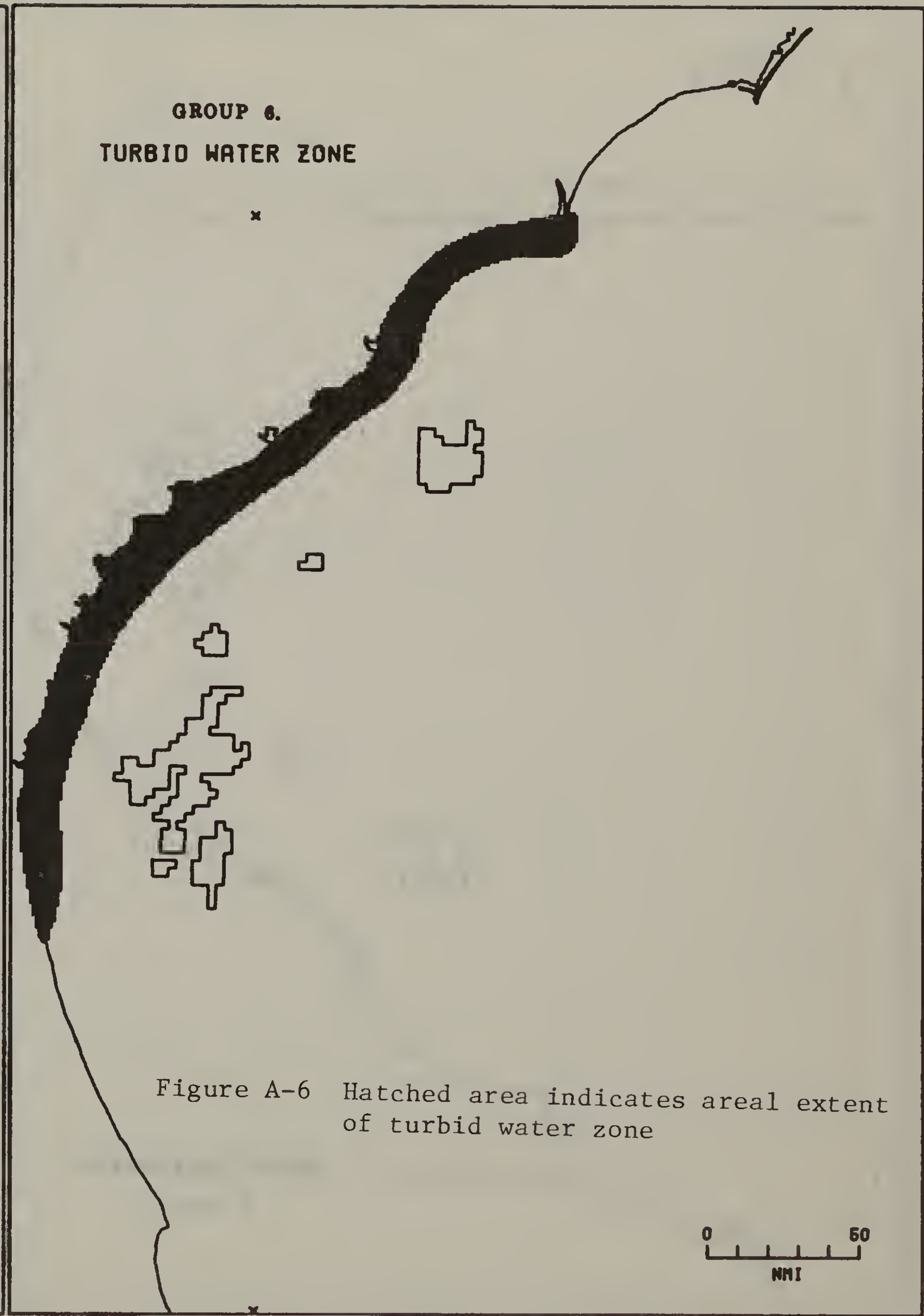

Figure A-6 Hatched area indicates areal extent of turbid water zone

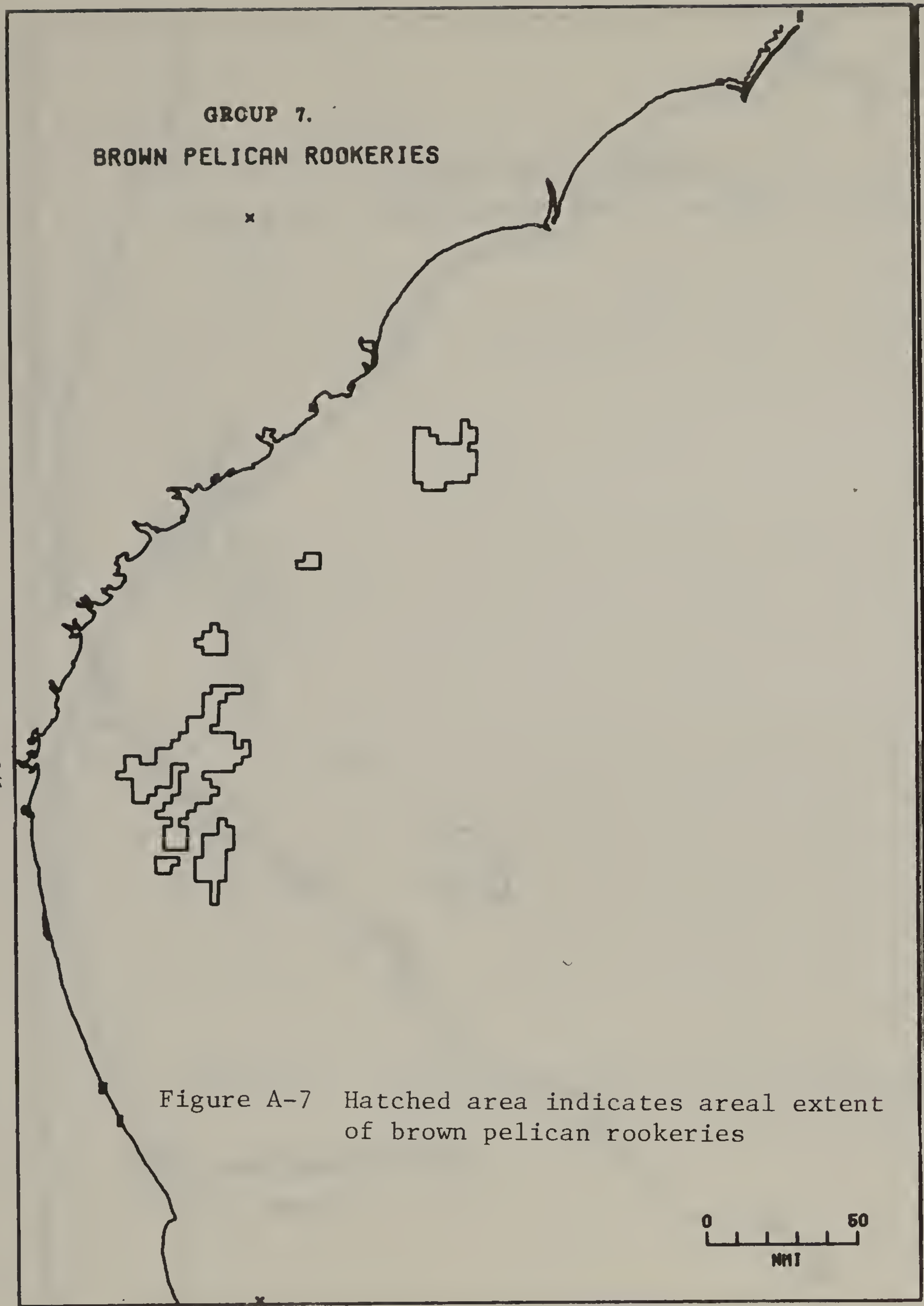

Figure A-7 Hatched area indicates areal extent of brown pelican rookeries

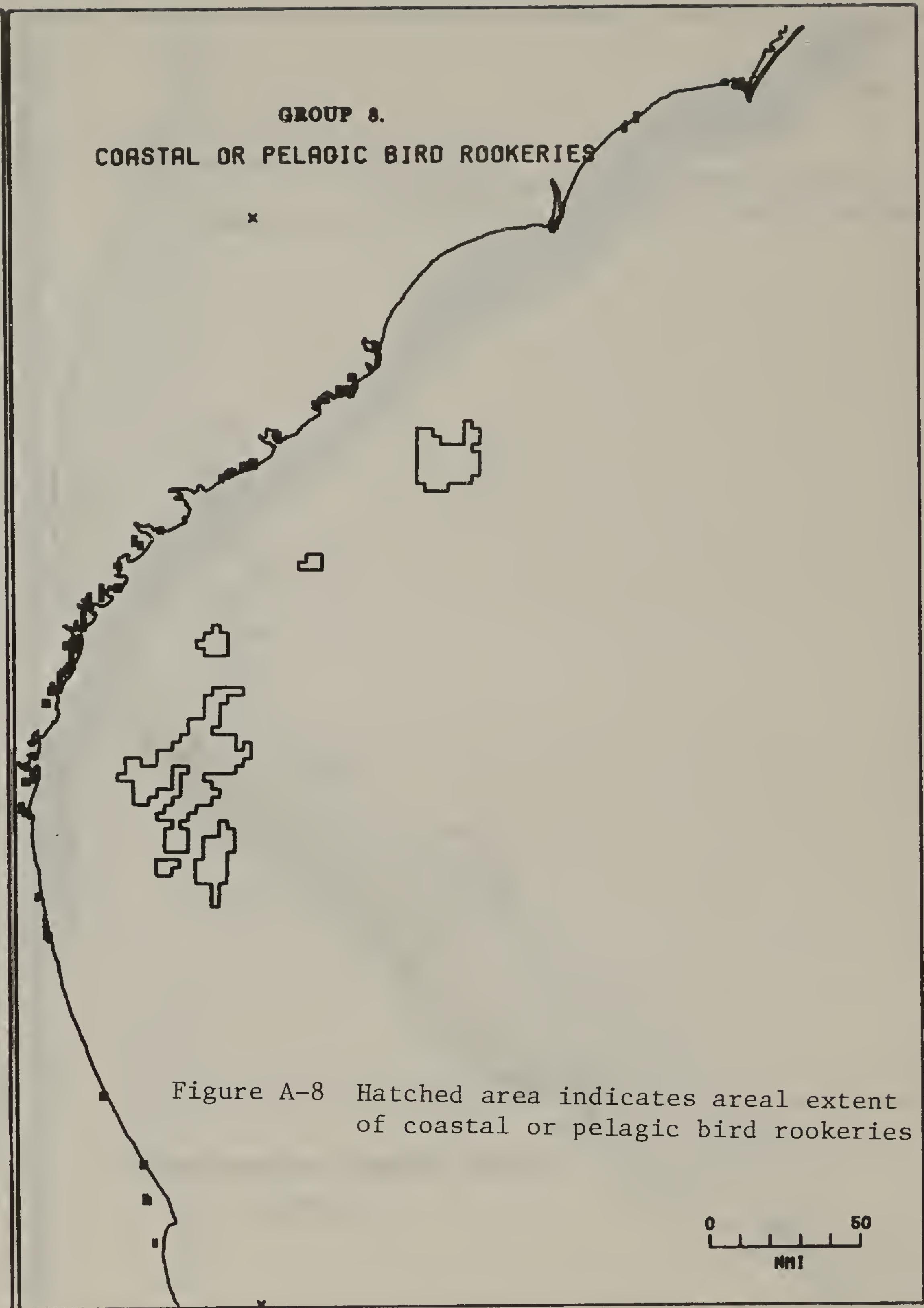

Figure A-8 Hatched area indicates areal extent of coastal or pelagic bird rookeries

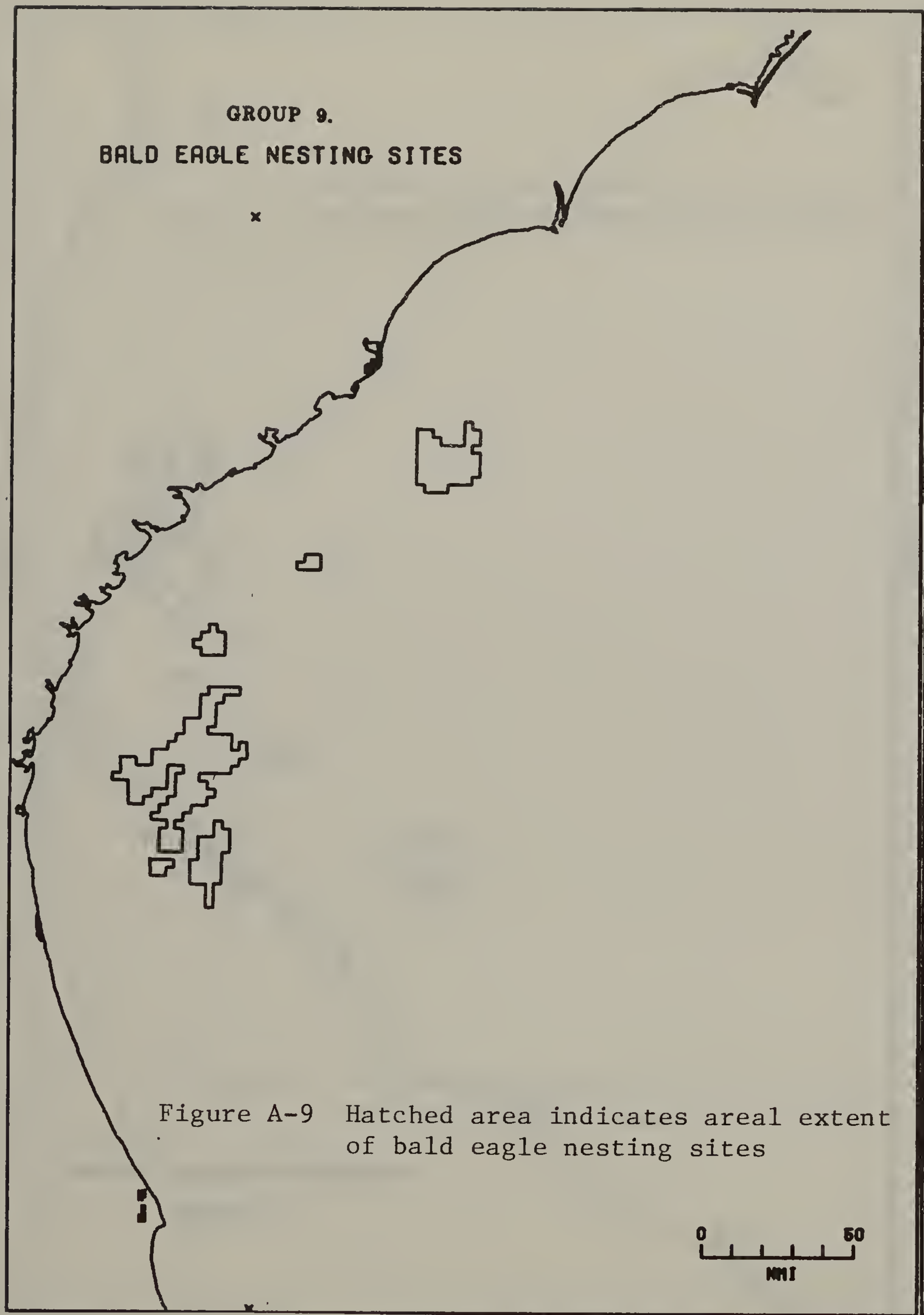

Figure A-9 Hatched area indicates areal extent of bald eagle nesting sites

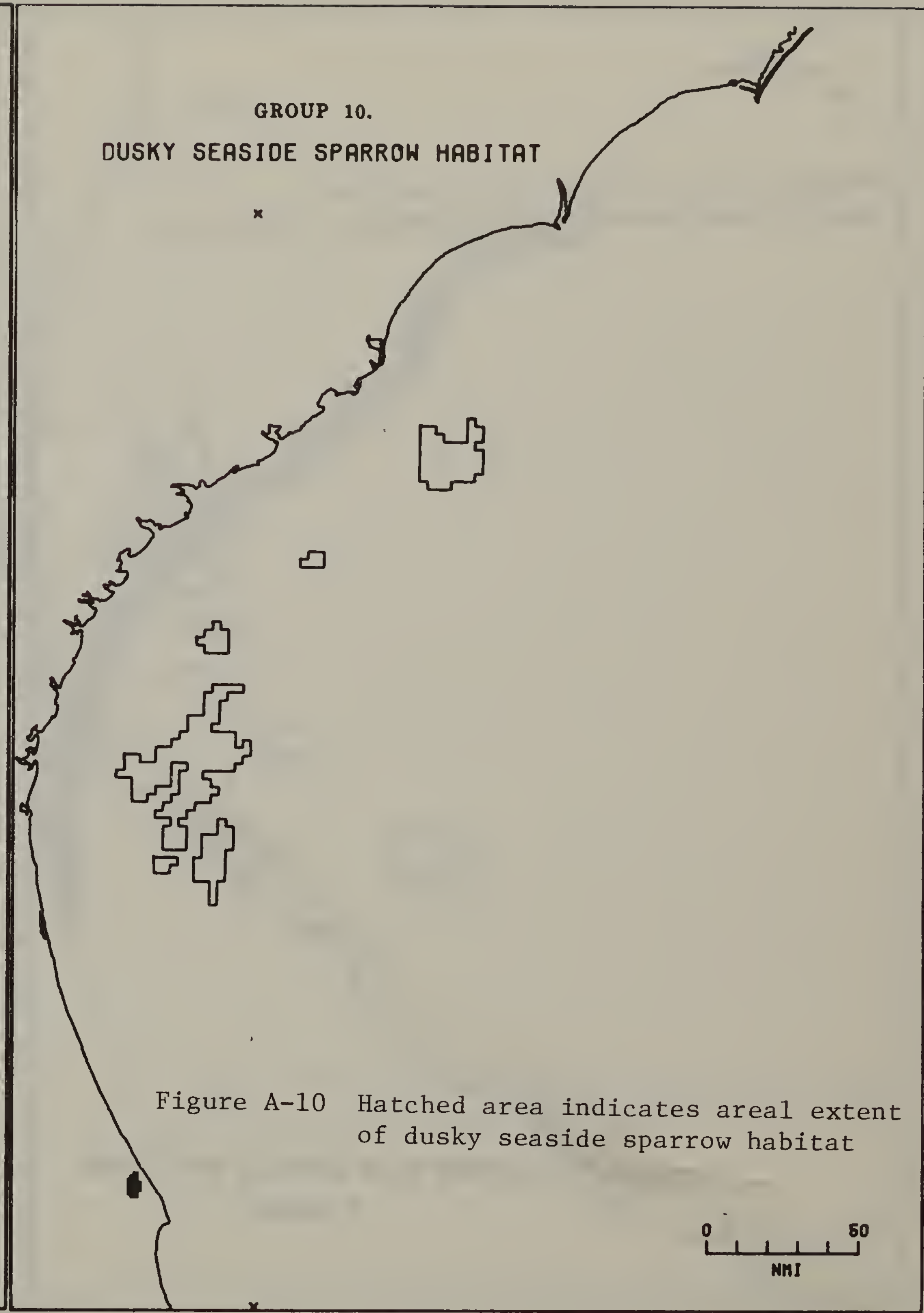

Figure A-10 Hatched area indicates areal extent of dusky seaside sparrow habitat

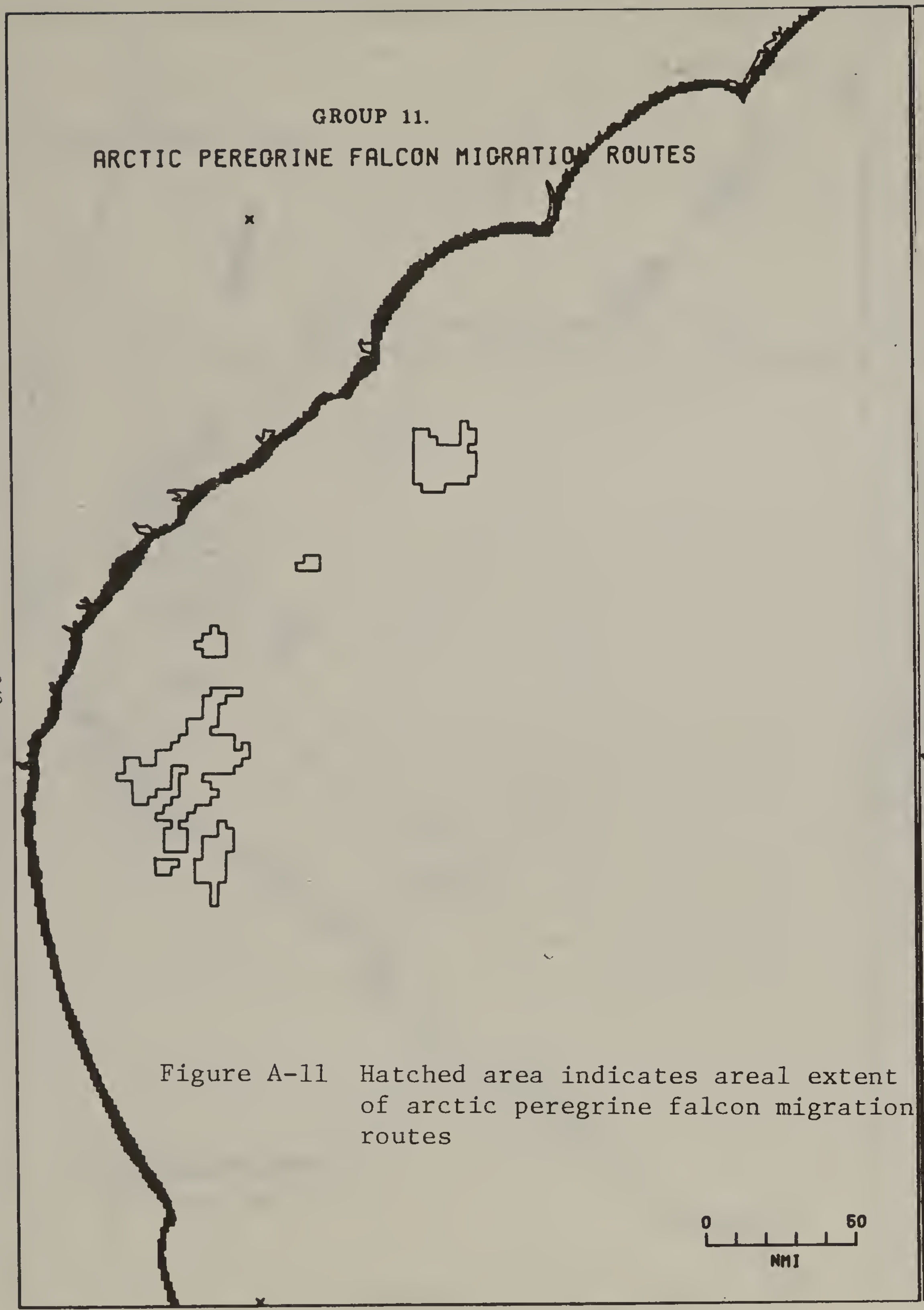

Figure A-11 Hatched area indicates areal extent of arctic peregrine falcon migration routes

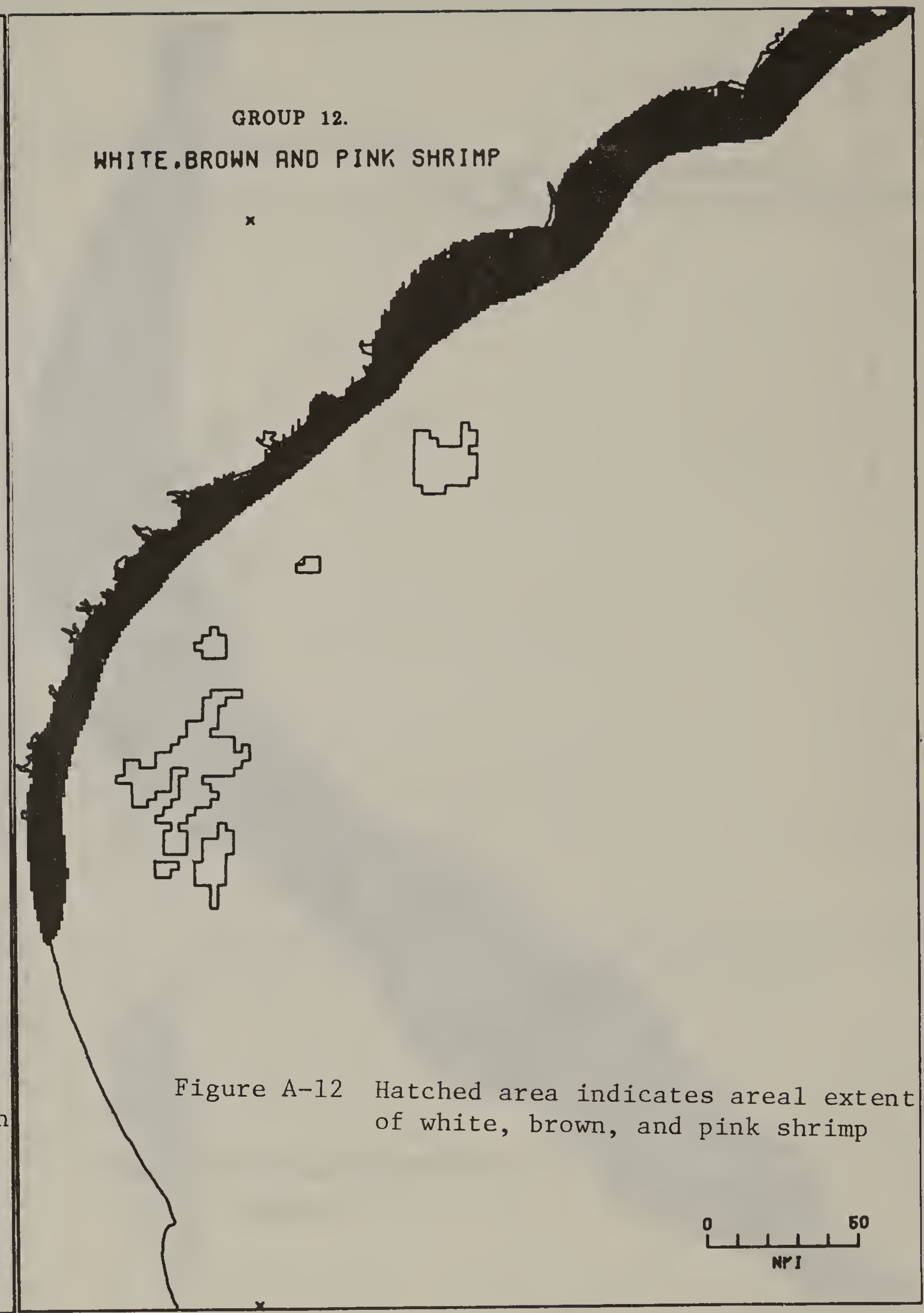

Figure A-12 Hatched area indicates areal extent of white, brown, and pink shrimp

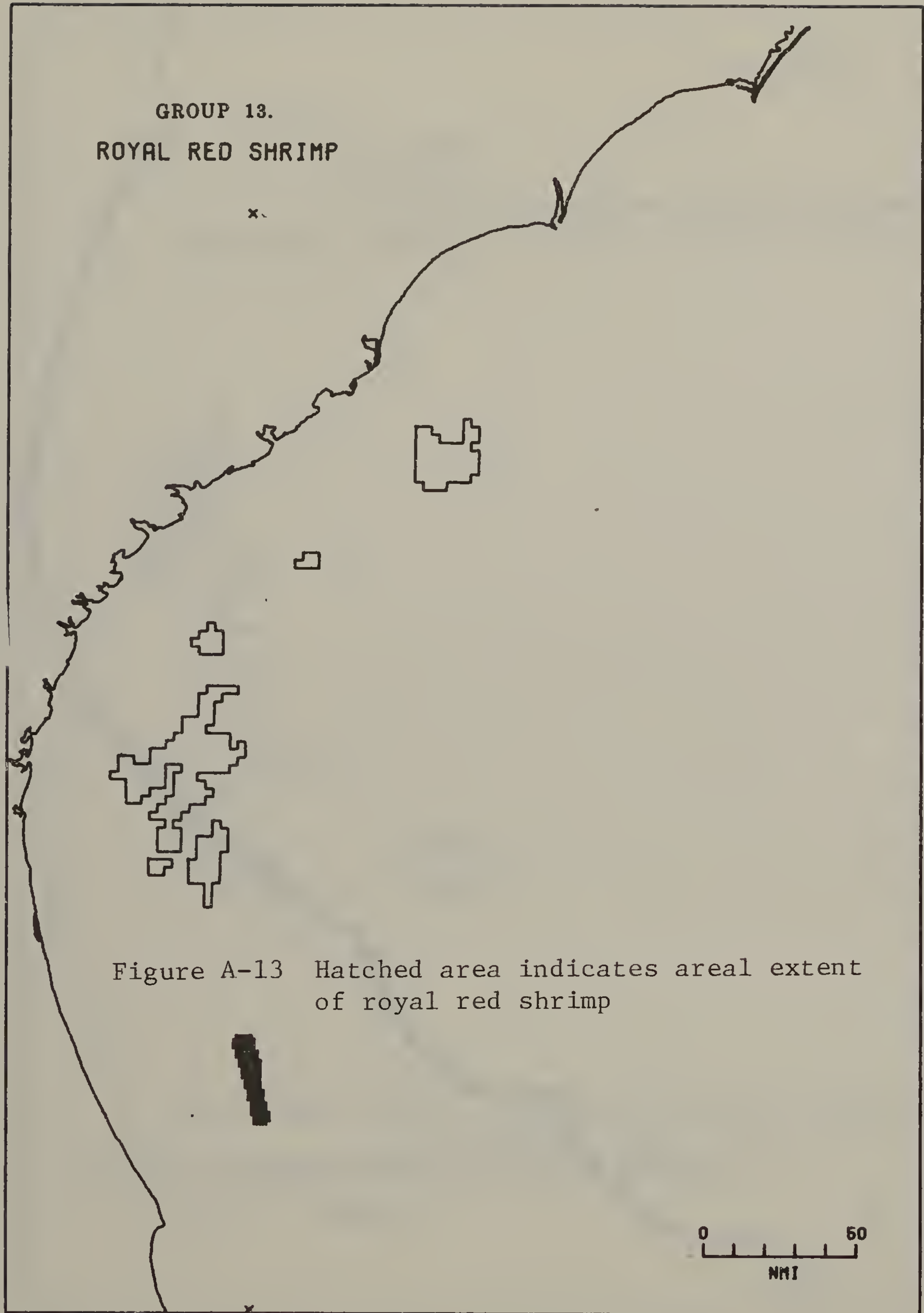

Figure A-13 Hatched area indicates areal extent of royal red shrimp

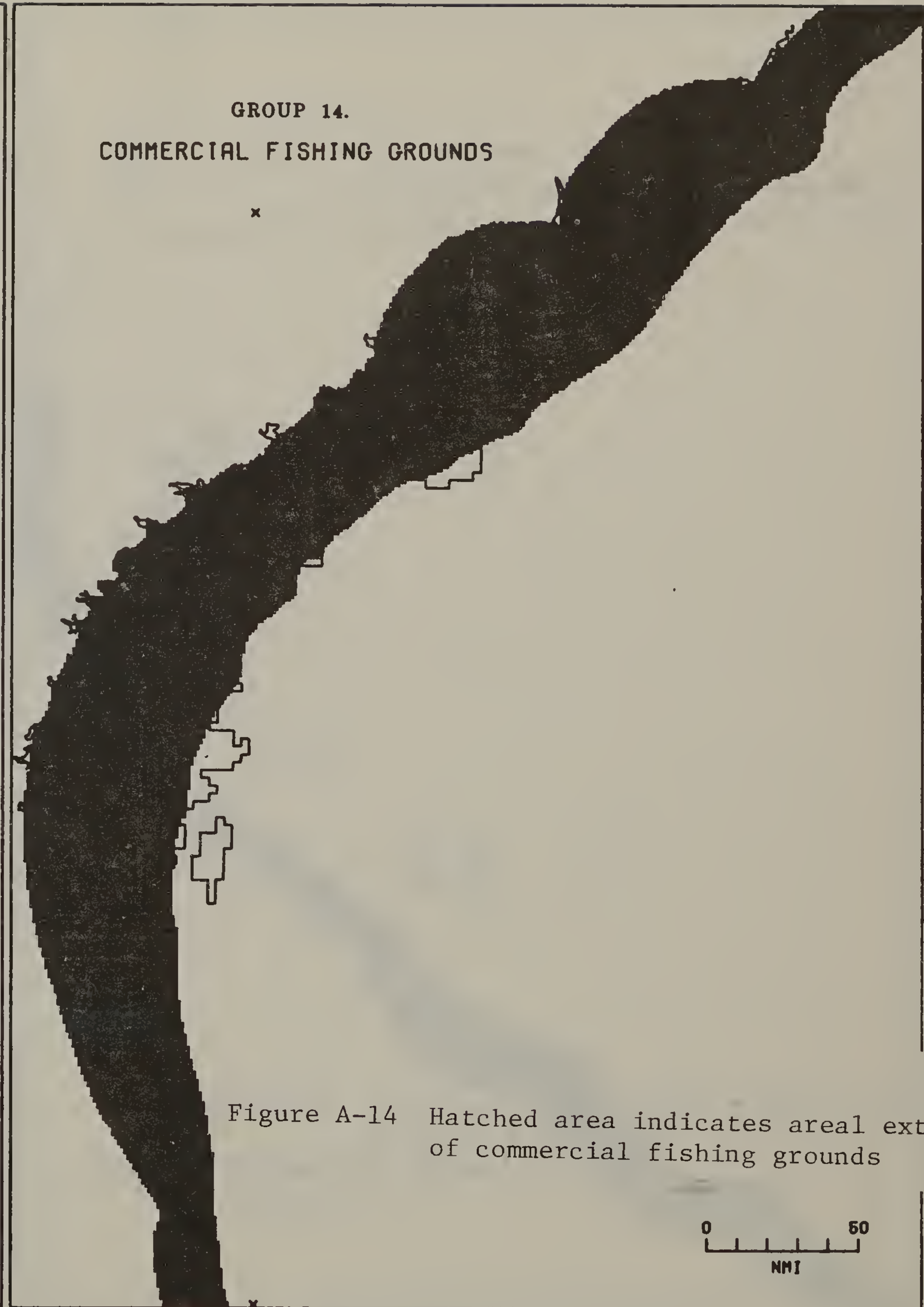

Figure A-14 Hatched area indicates areal extent of commercial fishing grounds

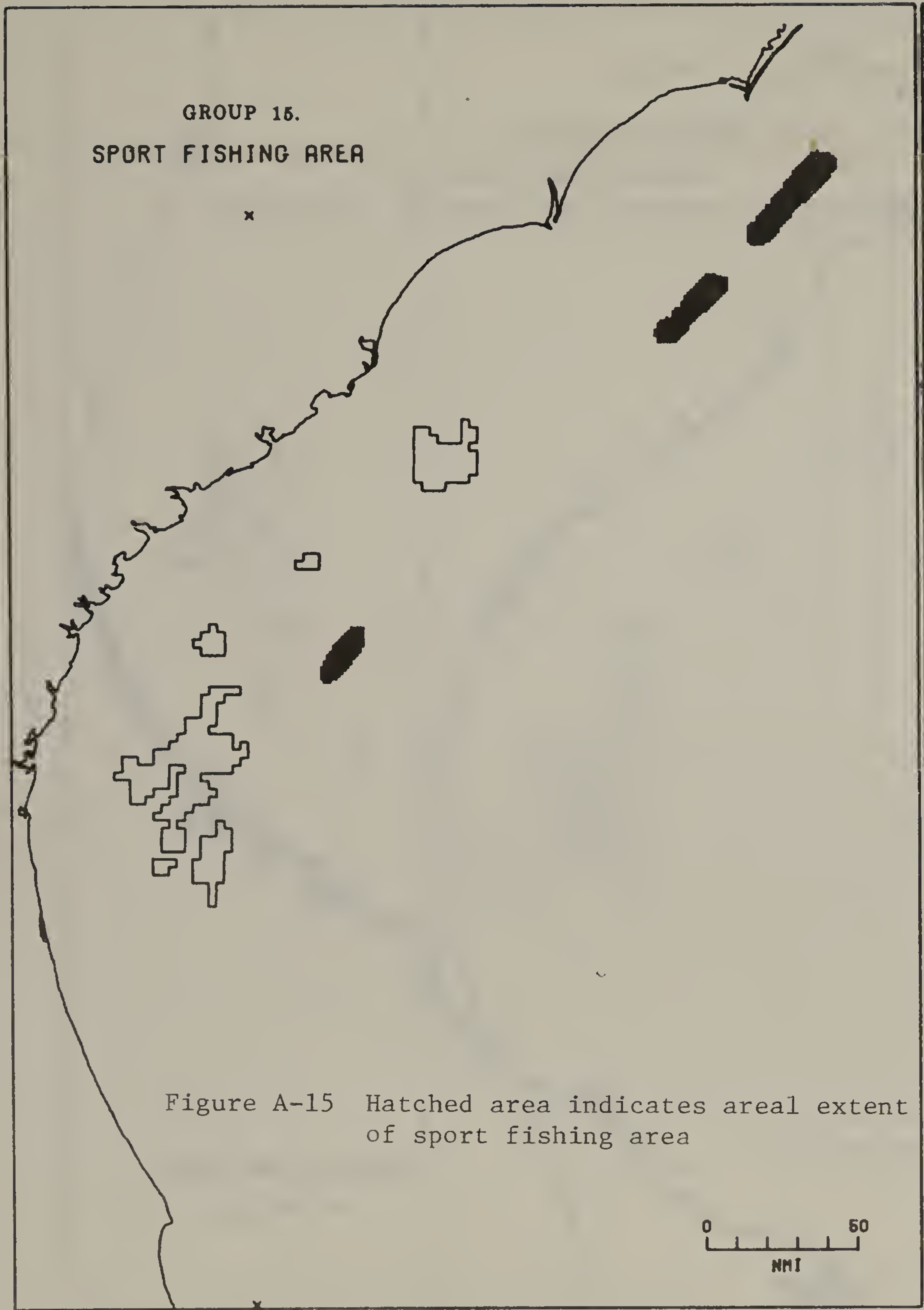

Figure A-15 Hatched area indicates areal extent of sport fishing area

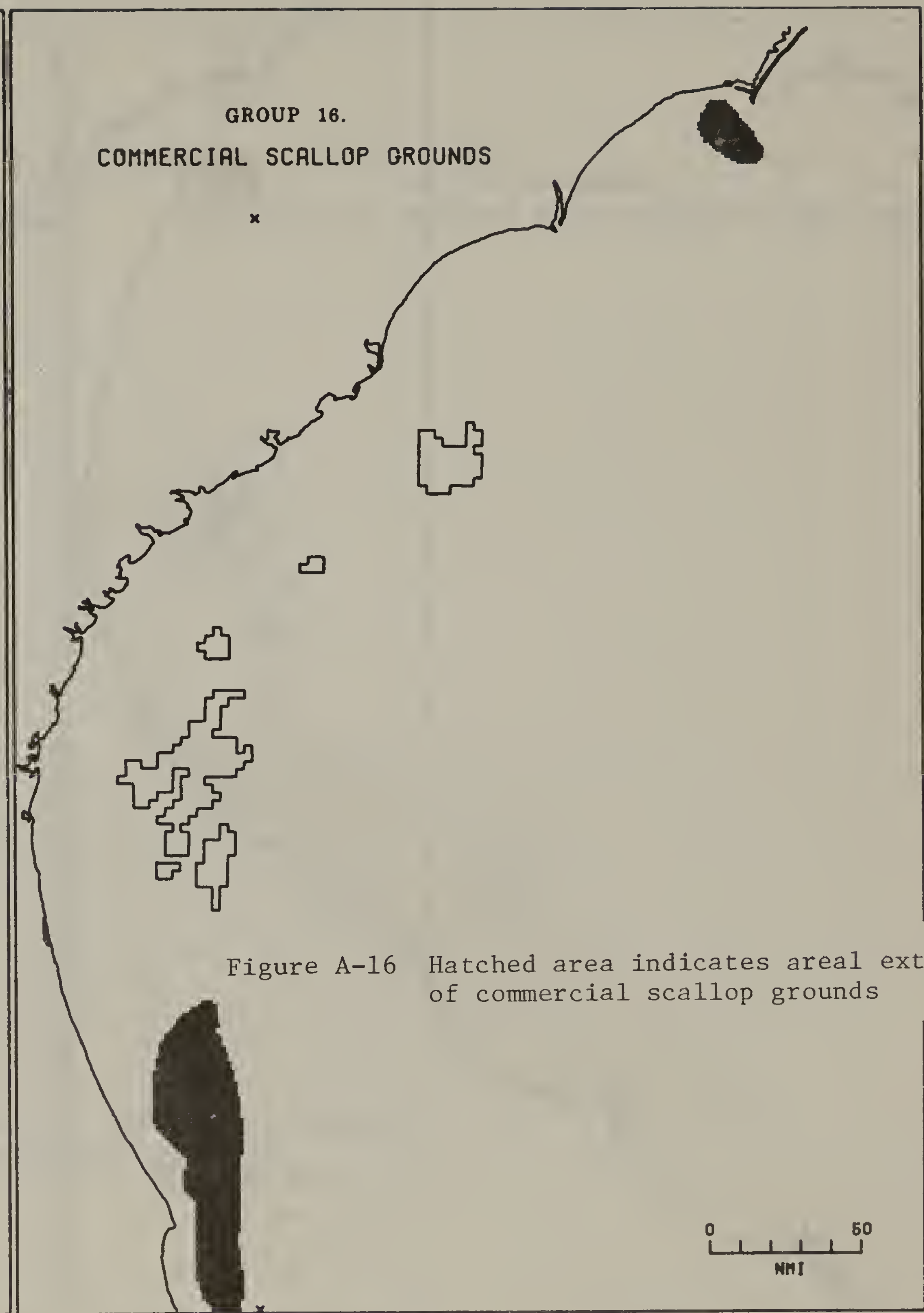

Figure A-16 Hatched area indicates areal extent of commercial scallop grounds

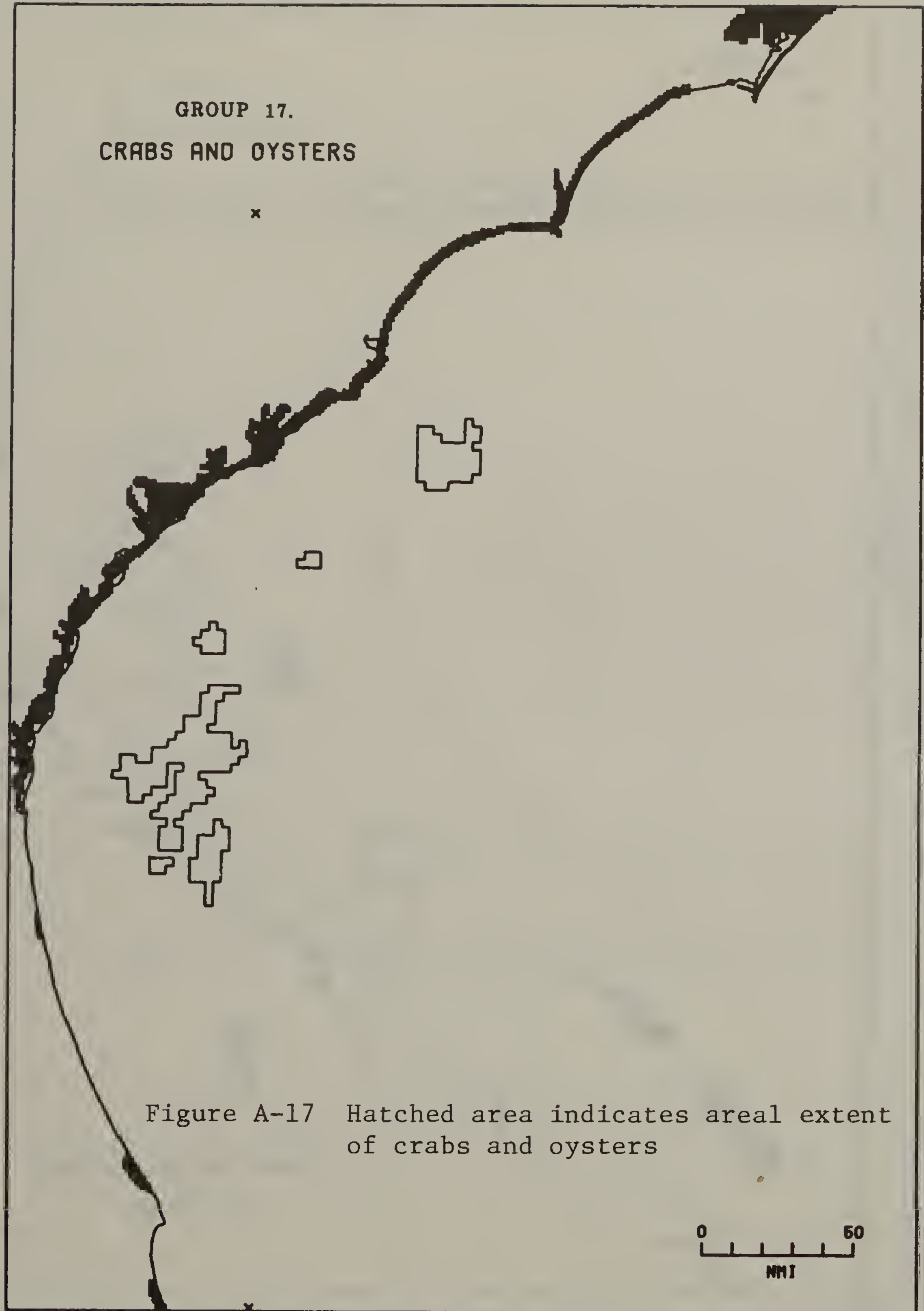

Figure A-17 Hatched area indicates areal extent of crabs and oysters

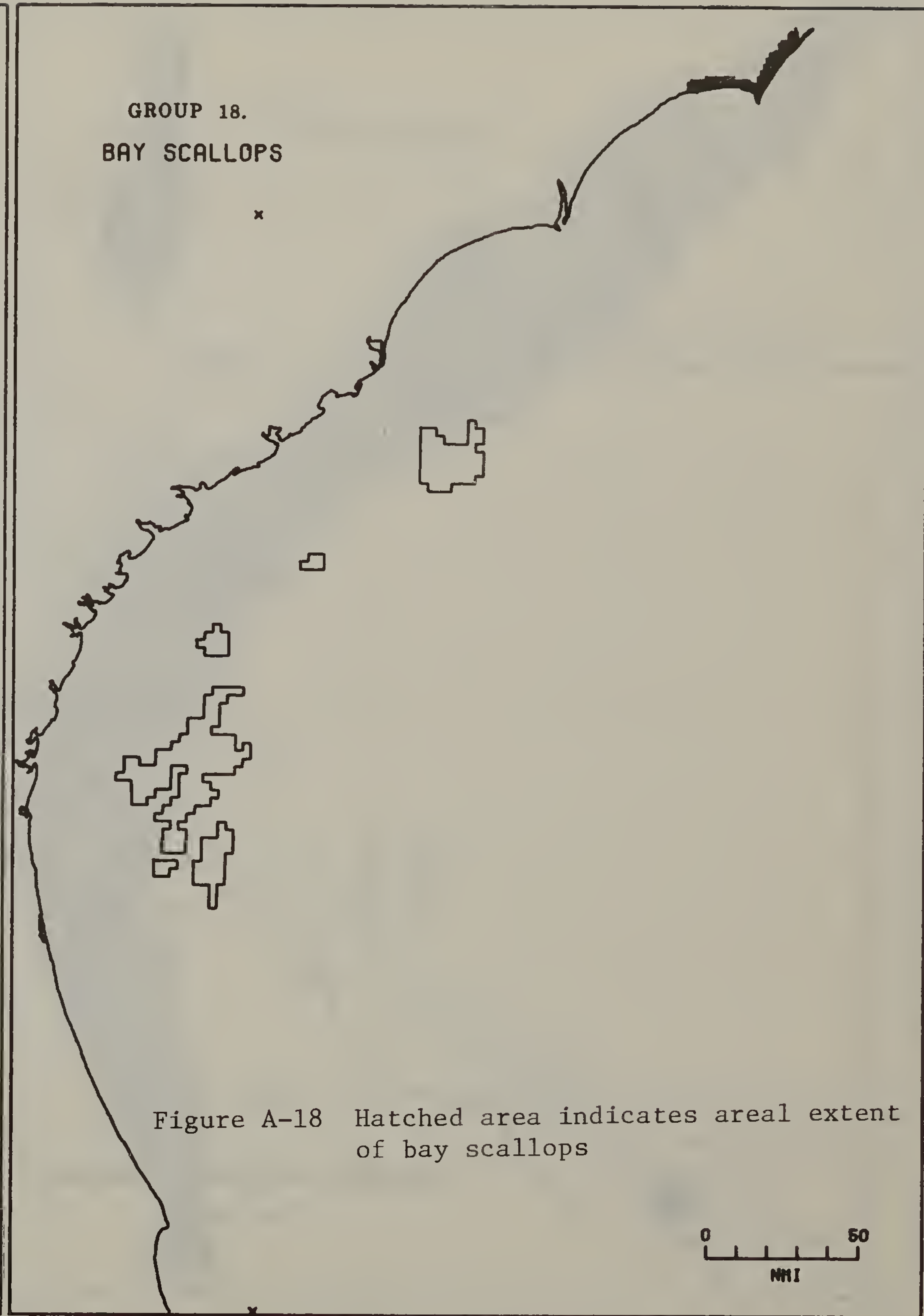

Figure A-18 Hatched area indicates areal extent of bay scallops

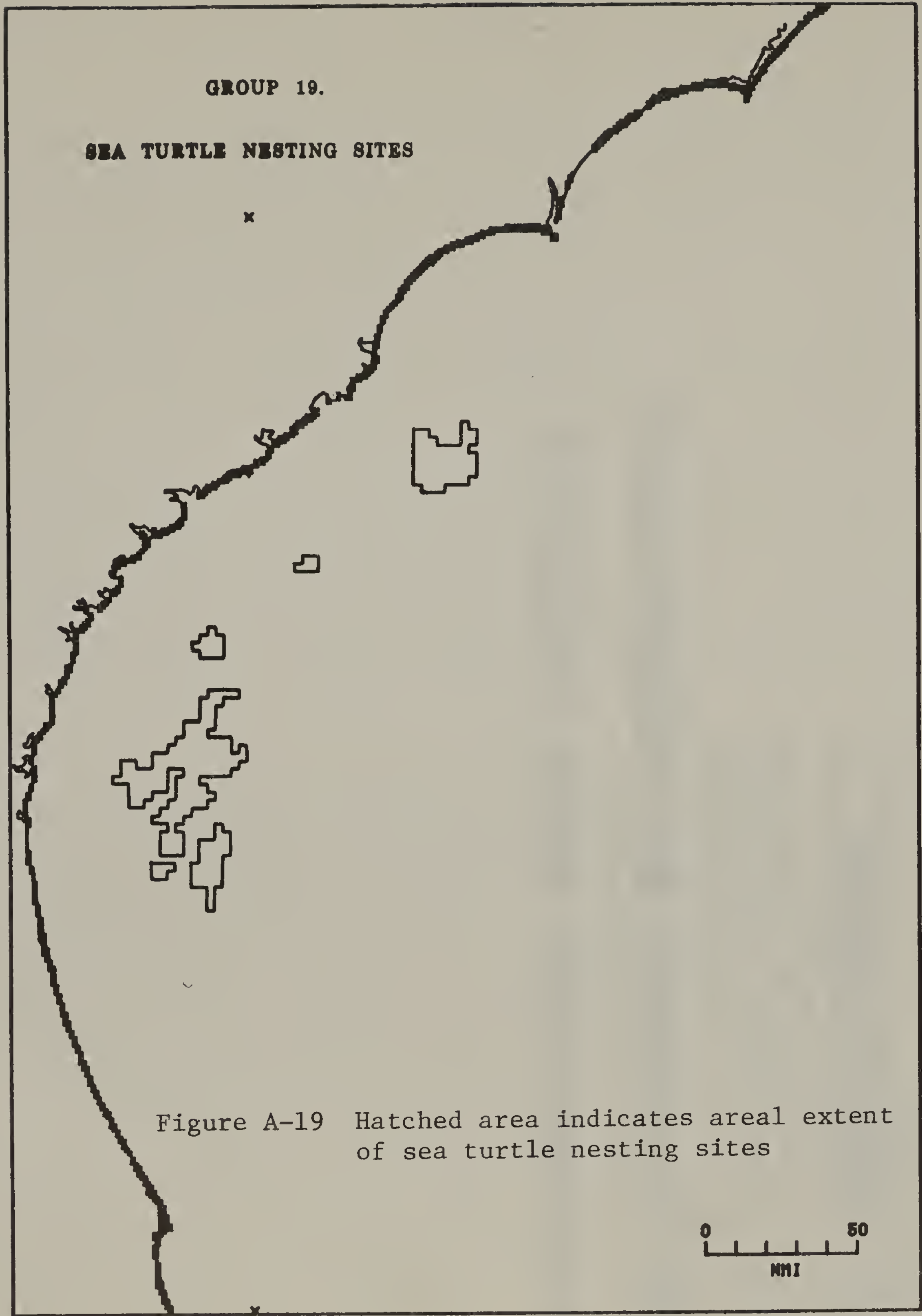

Figure A-19 Hatched area indicates areal extent of sea turtle nesting sites

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Appendix N

Examples of Notices to Lessees and Operators

UNITED STATES DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY—CONSERVATION DIVISION
EASTERN REGION—ATLANTIC AREA

NOTICE NO. 76-2

December 20, 1976

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE MID-ATLANTIC OUTER CONTINENTAL SHELF

Minimum Requirements for Operations Site Survey

1. *Introduction*

Exploratory and Development Plans and Modifications must include data about the environment and the analysis of these data to enable evaluation of the site as it may effect the specification of the operations. This notice defines the requirements for the operations site survey and for the submission of these data and analytic reports. Lease Stipulation No. 1 (Cultural Resource Protection) may be implemented depending on review of these data by the Atlantic Area Oil and Gas Supervisor for Operations.

2. *Survey Requirements*

a. *Areal extent*

The data and analyses submitted must be appropriate to the activity proposed both in type and areal extent.

Recorded images (e.g. side-scan sonar) of the sea floor will be required completely covering the area to be occupied plus a border beyond the farthest anchor scope to allow for margin of error in positioning the surveys and locating the operations at commencement.

The border around the planned area of operations shall be twice the sum of the radii of circular error probability 50% (C.E.P.) for the survey and for the location at first arrival on site. For example, if the survey C.E.P. is 75 m and the operation can be assured to have a C.E.P. of 75 m, then the border shall be 300 m. No Operational activity shall be commenced on any site until the location has been confirmed to within the required C.E.P.

b. *Fix Interval*

The Fix Interval for underway surveys shall not be significantly greater than the survey line spacing to enable determination of completeness of coverage and typing of data from one line to another.

c. *Surveys*

1. *Images of the sea floor.* Side-scan sonar dual coverage continuous recordings to 150 meters each side from not higher than 30 meters above the bottom to be run on 150 meter spacing, with cross lines every 600-800 meters.

Any program which generates recorded sea floor images, which can be demonstrated to completely cover the area of activity, would be acceptable as an alternative. For example, if navigation repeatability errors can be shown to be less than 30 m and side scan successfully images the sea floor to a lateral range of 130 m, the line spacing could be increased to 200 m.

2. *Bathymetry.* Determination of water depth by instrumental methods calibrated to within ½% and based on speed of sound data for the entire water column at the season of the survey. Determinations of water depth are to be made along all lines in Item 1 above.

3. *Sediment profiles.* Profile recordings of seismic reflections to a depth of 30 m (100 ft.) below sea floor with resolution of one millisecond (1 ms) or better. Spacing of 300-400 meters is required, to be consistent with geologic variations in this area, with cross lines every 600-800 meters.

4. *Shallow seismic.* Profiles clearly recording primary seismic reflections to 300 m (1000 ft.) below sea floor with resolution of ten milliseconds (10 ms) or better. Multiple reflections are a serious problem of interference in this area, so suppression of multiples by digital processing of true amplitude signals or recordings is required. Spacing of 300-400 meters is required, to be consistent with

geologic variations in this area, with cross lines every 600-800 meters.

These data need not be collected simultaneously with Item 3 above, but could be recorded on alternate lines while covering the spacing requirement for side-scan imaging in Item 1 above.

5. *Seismic velocities.* For conversion of seismic reflection time to depth, seismic velocities may be derived from multichannel velocity scan analysis, seismic refraction data, or in the absence of any such data an assumed velocity should be justified by argument from regional or geological information.

6. *Sampling and measurement of engineering properties of soils.* The methods of sampling and measurement shall be chosen to provide the kind of data necessary for the design engineering of the operations proposed. For example, foundation design for fixed structures will require knowledge of soil properties to the greatest bearing depth, while design of well-head control for areas of potential mass movement will require knowledge of soil properties with depth not only at the immediate location, but up-slope and down-slope as well.

Special attention is called to Lease Stipulation No. 8 mass movement of sediment: On these tracts, extensive profiling and physical soils testing may be required to substantiate that the design of sea-floor well control installations be capable of withstanding possible mass movement, or that the specific sites on which they are to be located are not subject to this hazard.

3. *Reports*

a. Two copies of the following shall be submitted to the District Supervisor as they become available.

b. All data of the requirement (2.c.) must be submitted for review. Copies will probably be acceptable (preferably on continuous flow microfilm reduced not more than 20:1 from originals), but original data may be requested if the quality of the copy is in doubt.

c. Positioning maps showing survey vessel tracks with navigation fix locations, locations of sampling, and referenced to the locations of areas of planned activity are required to be submitted. These maps must be prepared at a scale of between 1:5,000 and 1:12,000 on a base showing the lease boundaries, geographic coordinates every minute of latitude and longitude, and any other coordinates used in positioning. Fixes and locations shall be clearly identified on the map and legend, and shall be correspondingly identified on data recordings and interpretations, and in text references.

d. A summary report of analyses of the required data as a minimum shall be prepared by analysts professionally competent to evaluate the data for the planned operations. These authors shall be identified, and shall sign the report.

UNITED STATES DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

GULF OF MEXICO AREA

NOTICE NO. 75-3

January 20, 1975—(Supersedes No. 74-10)

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO AREA

Minimum Geophysical Survey Requirements to Protect Cultural Resources

Recent OCS leases include stipulations concerning archaeological surveys. Should such an archaeological survey be required in the leased area, or area sought for permit, the following minimum requirements must be fulfilled. These requirements will be effective as of the date of this notice and shall apply also to all existing leases that contain archaeological stipulations, including MAFLA leases, where the archaeological surveys have not yet been conducted.

Prior to drilling operations or the installation of any structure or pipeline, the lessee shall conduct a high resolution geophysical survey in the immediate area to determine the possible existence of a cultural resource. The following equipment is required in performing the survey. All equipment shall be representative of the state of technological development.

A. *Magnetometer*—Total field intensity instruments are needed. The sensor of the magnetometer should be trailed as near as possible to the sea floor; six meters or less is recommended. Knowledge of the sensor depth of tow above the bottom is highly desirable for future analyses.

B. *Dual Side Scan Sonar*—Coverage of the sea floor at a range width of at least 150 meters per side in the proposed area is needed.

C. *Depth Sounder and Sub-bottom Profiler*—An analog recorder shall be used for bathymetry and the profiler shall be capable of resolving the upper 50 feet of sediment.

Navigation for the survey shall utilize state-of-the-art positioning systems correlated to annotated geophysical records. Navigation accuracy shall be on the order of ±50 feet at 200 miles.

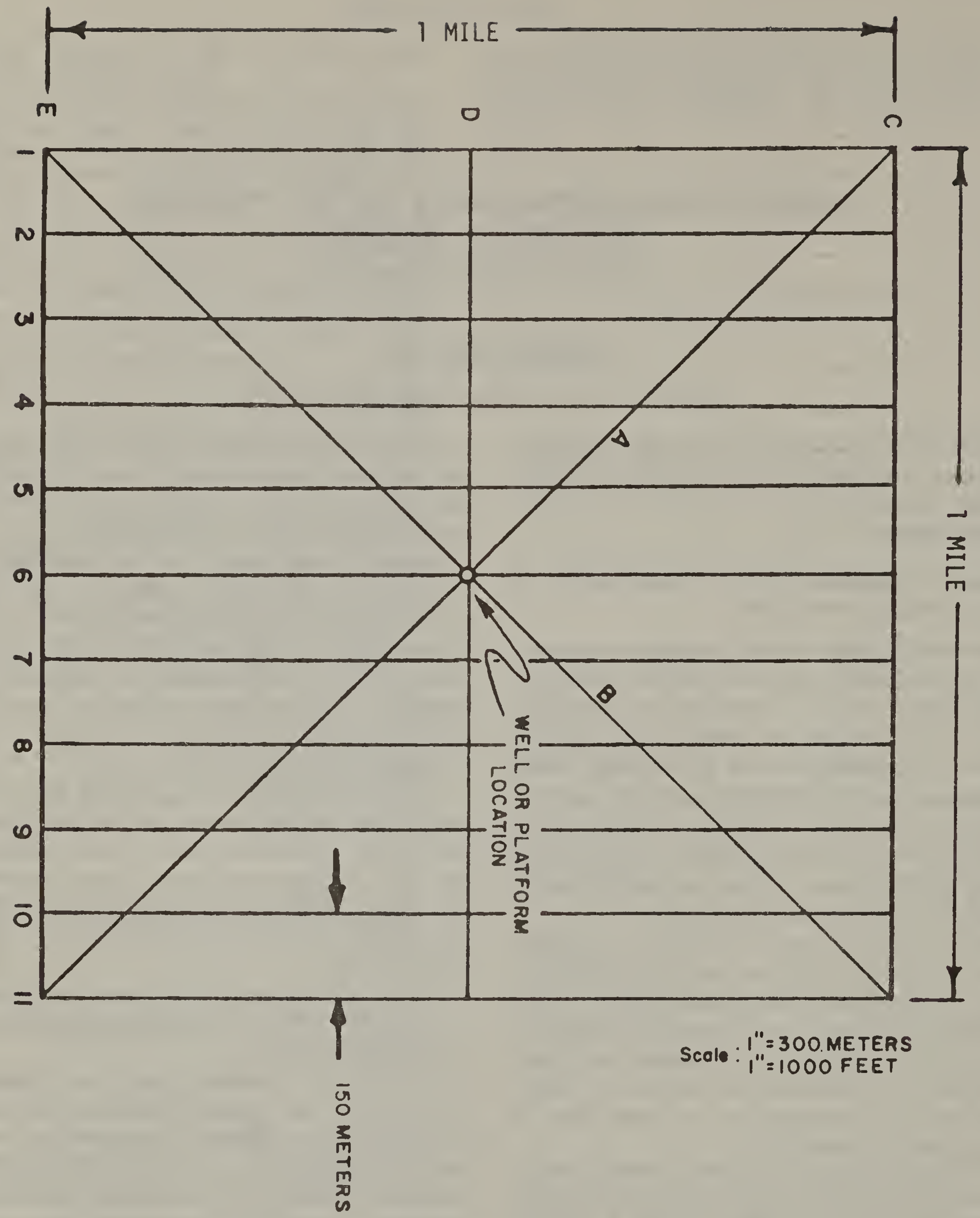
Optional tools could include cameras, underwater TV, divers, and cores. Any engineering soil borings which are obtained shall be made available for the archaeologist's inspection. These data shall be evaluated for indications of aboriginal habitation sites as well as for historic sites. The tract or survey line spacing shall follow the attached illustrated plans.

For a single-drill site or platform location, all geophysical equipment shall run an area approximately one mile square with eleven principal survey lines spaced 150 meters apart with three cross-lines. In addition, two diagonal lines centered on the proposed drill site shall be run. (See attached Plan A.)

For an entire lease block, or significant portions, a 150 meter × 1000 meter spacing shall be used. (See attached Plan B.)

For a pipeline installation, three principal survey lines shall be run, one following the exact course of the proposed pipeline with an offset line on either side spaced to coincide with the area which would be disturbed by the barge anchors. The distance of these offset lines from the proposed pipeline route cannot be stated specifically since this is a function of water depth and equipment. (See attached Plan C.)

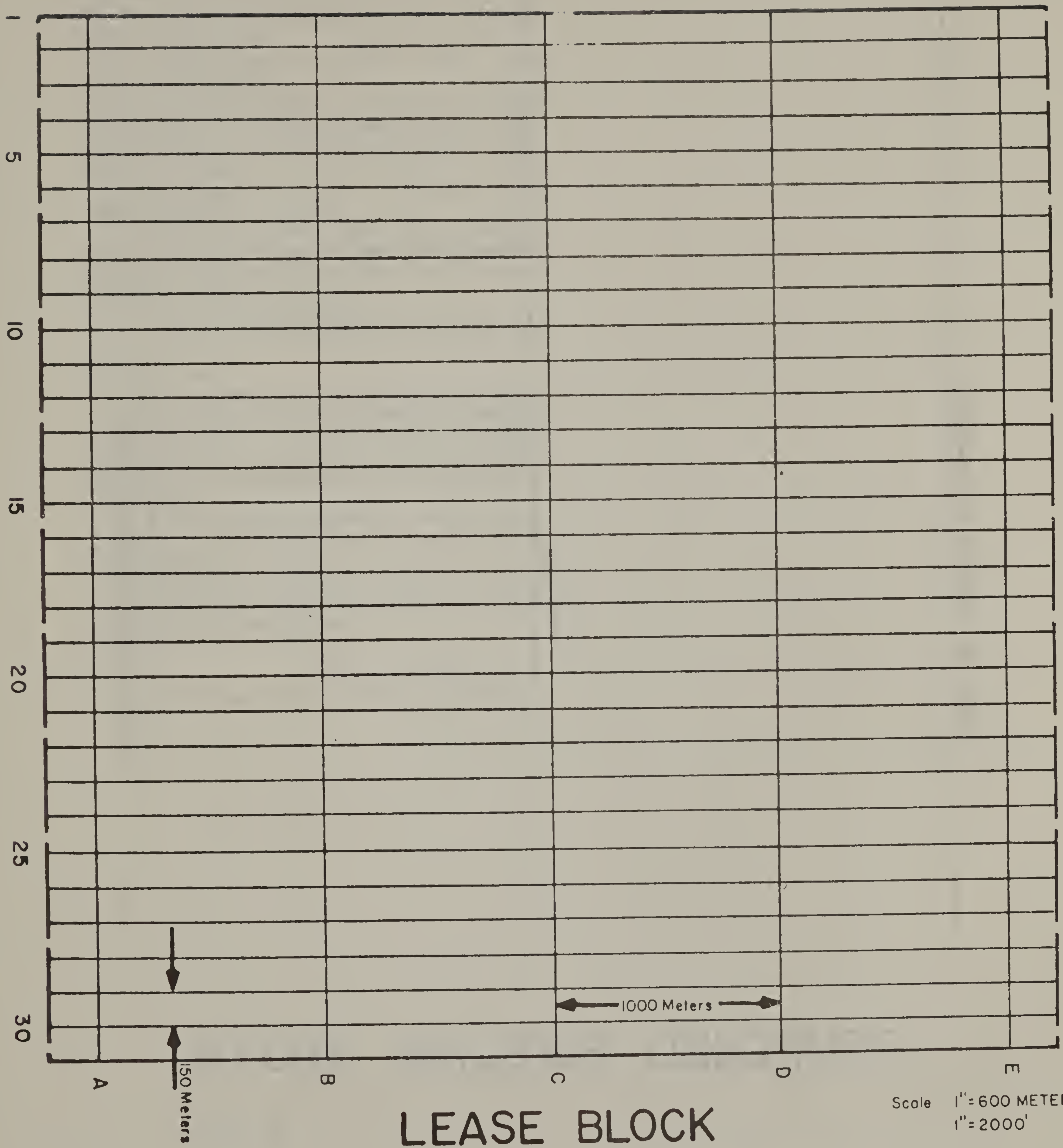
A professional underwater archaeologist is not required to be present on all survey activities. A geophysicist must accompany the survey to insure that the equipment is properly tuned and records are accurate and readable. The records shall be inspected by the archaeologist along with the sur-



WELL OR PLATFORM LOCATION

GEOPHYSICAL SURVEY GRID TO DETERMINE THE EXISTENCE OF CULTURAL RESOURCES

PLAN "A"

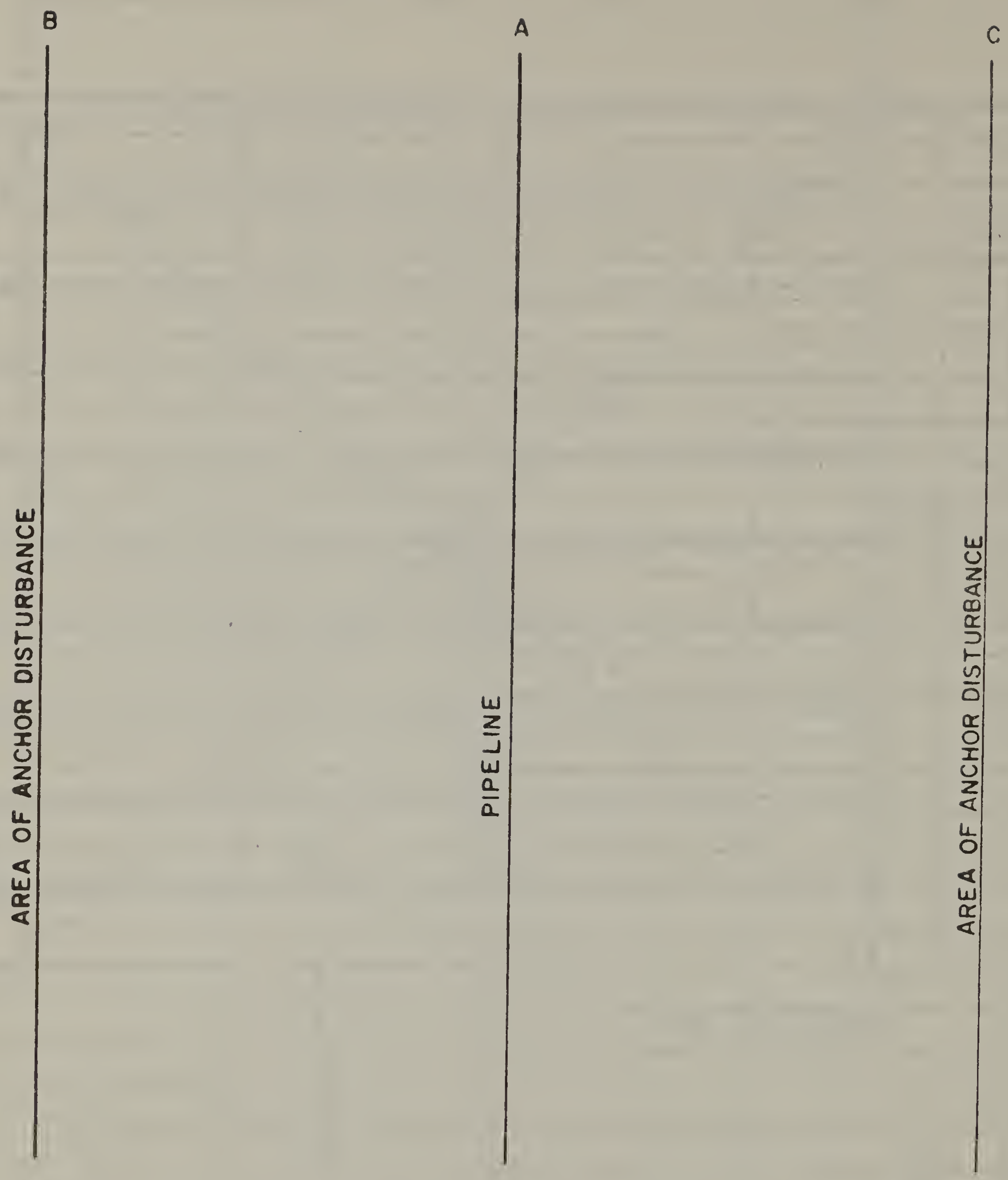


Scale 1" = 600 METERS
1" = 2000'

LEASE BLOCK

GEOPHYSICAL SURVEY GRID TO DETERMINE THE EXISTENCE OF CULTURAL RESOURCES

PLAN "B"



PROPOSED PIPELINE ROUTE

No Scale

GEOPHYSICAL SURVEY GRID TO DETERMINE THE EXISTENCE OF CULTURAL RESOURCES

PLAN "C"

vey geophysicist who shall advise the archaeologist as to the record quality and anomaly occurrences. The data will be maintained by the lessee and shall be available to BLM and USGS upon request.

Survey Report Format

The archaeological survey shall include, as a minimum, the following:

1. Description of tract surveyed to include tract number, OCS number, block number, geographic area, e.g., Mobile South No. 1 Area, and water depth.

2. (a) Map (1″ = 2,000′) of the lease block showing the area surveyed.

(b) Navigation postplot Map (1″ = 1,000′) of area surveyed showing tract lines and shotpoints with U.T.M. X and Y coordinates and latitude-longitude reference points.

3. Survey personnel and duties.

4. Survey instrumentation, procedures and logs.

5. Sea state.

6. The original of a selected line of survey data for each instrument used shall be submitted with each report. In all cases where an anomaly is encountered, the original of all survey data for the line(s) indicating the anomaly shall be submitted.

7. Archaeological assessment, with a signed statement as to the possible existence of a cultural resource.

8. Two copies of the report shall be submitted to this office and also two copies to the New Orleans OCS Office, BLM.

/s/ D. W. Solanas

Oil and Gas Supervisor, Field Operations, Gulf of Mexico Area

Appendix O

The Department of Interior's Policy Relative to Potential Oil and Gas Leasing

OFFICE OF THE SECRETARY

For Release May 17, 1977

Revised OCS Planning Schedule Announced

Secretary of the Interior Cecil D. Andrus announced today the outline of his new policy on Outer Continental Shelf oil and gas leasing, including a new planning schedule for lease sales through the end of 1978. The schedule replaces the one issued by former Secretary Kleppe in January.

"The principal goal of the program continues to be the increased production of oil and gas from U.S. offshore areas," Secretary Andrus said. "Completion of development in known areas, along with a steady exploration and development pattern in frontier areas (including Alaska), are the twin thrusts of the program. There remains a critical need to develop the Nation's overall oil and gas resources as a part of the President's National Energy Plan.

"What is substantially different is the manner in which the program will be carried out in relation to the States, local government and the general public. While expecting that every region will support and contribute to the program, I intend to recognize fully the distinct social, economic, technological, cultural and environmental elements associated with each individual region and sale.

"The emphasis will be on working with the States and others to resolve key issues associated with sales or the opening of new regions. I believe this objective can be accomplished most effectively by providing adequate time in the planning process for resolving conflicts and involving coastal States in a significant manner.

"I firmly believe that we have and will benefit from the advice of the coastal States and, in turn, the States may better understand the impacts they must plan for. The schedule which I am proposing today is an attempt to take all these concerns into account and to provide a plan of action which will permit this Nation to reduce its dependence on insecure and costly foreign imports, but also can be carried out credibly with public support. Both the American public and the industry need more than a fast schedule; they need a reliable schedule."

The first sale listed on the planning schedule is in the Gulf of Mexico (OCS No. 47) for June 1977. The final impact statement for this sale was issued in February 1977. Secretary Andrus has made a final review of this sale and will announce a sale date shortly. The sale was originally proposed for April 1977 but its final review was delayed pending the completion of geologic studies on some tracts.

The planning schedule also includes a proposed sale in the OCS Area of Alaska's Cook Inlet for October, 1977. This sale had been scheduled for February 23 but was cancelled by Secretary Andrus February 7. He said at that time that he wanted to examine the studies, comments and options concerning the sale before deciding whether the sale should proceed. An announcement will be made later, Secretary Andrus said, concerning the specific sale date, tracts and acreage to be included in the sale and special lease stipulations.

Other sales included in the planning schedule are: North Atlantic OCS Sale 42 for November 1977; South Atlantic OCS Sale for January 1978; Gulf of Mexico OCS Sale 45 for February 1978; Eastern Gulf of Mexico OCS Sale for August 1978; Gulf of Mexico OCS Sale 51 for October 1978; and Mid-Atlantic OCS Sale 49 for December 1978.

Secretary Andrus said a further updating of the Department's planning schedule through 1980 will be issued in August after a similar careful study of possible sales for that period. Planning activities will continue for sales which could be held in the 1980 time frame.

The Kodiak Alaska OCS 46 sale, previously scheduled for November 1977, Southern California OCS Sale 48 previously scheduled for March 1978, and the South Atlantic Blake Plateau Sale 54, previously scheduled for December 1978, are not included on the planning schedule for the period ending in December 1978, but will be considered in the planning schedule to be developed for period through 1980. The General Pacific OCS Sale 53, previously scheduled for October 1978, may be dropped from the planning schedule.

Secretary Andrus also announced plans to begin cooperative work with the State of Alaska for a joint sale in the Beaufort Sea in 1979.

Secretary Andrus emphasized that the sale schedule is for planning purposes only. "I will make decisions on whether to proceed with specific sales only after all the requirements of the National Environmental Policy Act have been met and I have personally studied the comments

of the Governors of the affected States and others on all issues related to the sale,'' he said.

''The planning schedule will permit government, industry and public interest preparations but in making decisions on specific sales we will be bound not by a desire to achieve 'a schedule.' but to making the best decision based on all the information and analyses which are available at that time,'' he added.

A detailed chart showing the new planning schedule for the various steps in the environmental review process will be issued shortly.

OFFICE OF THE SECRETARY

For Release May 25, 1977

Revised OCS Planning Schedule

A revised planning schedule for oil and gas lease sales on the Outer Continental Shelf was announced May 17, 1977, by the Secretary of the Interior Cecil D. Andrus. The proposed schedule is for the period ending December 1978.

A chart showing specifics of the new planning schedule is attached. It replaces an earlier tentative schedule issued in January 1977 by former Secretary Thomas Kleppe.

Secretary Andrus emphasized that the sale schedule is for planning purposes only. ''I will make decisions on whether to proceed with specific sales only after all the requirements of the National Environmental Policy Act have been met and I have personally studied the comments of the Governors of the affected States and others on all issues related to the sale,'' he said.

''The planning schedule will permit government, industry, and public interest preparations but in making decisions on specific sales we will be bound not by a desire to achieve 'a schedule' but to making the best decision based on all the information and analyses which are available at that time,'' he added.

Also attached is a description of the successive steps taken to arrive at a decision as to whether a proposed OCS oil and gas lease sale should or should not be held.

OFFICE OF THE SECRETARY

For Release August 23, 1977

Andrus Announces Schedule for OCS Lease Sales

Secretary of the Interior Cecil D. Andrus announced today a comprehensive revised planning schedule for oil and gas lease sales on the Outer Continental Shelf (OCS) for the period 1979 through 1981.

The schedule supplements the revised schedule for 1977 and 1978 which was issued by the Secretary May 17, 1977.

''Because of the critical importance of sound development of the OCS to assist in meeting our domestic energy needs,'' Secretary Andrus said, ''the planning schedule has been prepared in close consultation with the affected coastal States and takes into account the comments received from them and from local governments, industry, environmental groups and other interested parties.

''The response which we received from our June 15 request for comments and information on the OCS program aided us materially in developing the schedule.

''I believe the schedule carries out our policy of giving the States an opportunity to participate in the leasing process, of having all regions of the country contribute to meeting our domestic energy needs, and of balancing energy potential with environmental costs.

''The schedule also takes into account the additional environmental safeguards which we expect will be put into effect shortly either through administrative action or because of passage of legislation to amend the OCS Lands Act. These include the requirement to prepare a development phase environmental impact statement and provision for a 60-day period for State review of a proposed notice of sale.

The schedule calls for five sales in 1979, four in 1980, and six in 1981. It includes five Atlantic coast sales, two California coast sales, three Gulf of Mexico sales, and five sales in OCS areas of Alaska.

There is an approximate three-year interval between the first sales in a frontier area and subsequent sales in the same geologic province. Secretary Andrus said that this interval would provide for an orderly level of activity for both exploration and development and permit the use

of exploratory results from one sale in making tract selections for a later sale.

"Comments from the coastal States indicated their interest in maintaining onshore activity at a steady level in order to avoid a boom and bust cycle," Secretary Andrus said. "Ideally, just as exploratory activities from one lease sale are beginning to subside, exploratory activity from a second sale would begin to pick up. Later, the same pattern would prevail for development and production phases.

"Development of several of the frontier areas in the OCS off the coast of Alaska, such as the Beaufort Sea, pose significant technological challenges. It was decided to offer leases in these areas with the understanding that we will proceed with these sales only if there is existing technology for exploratory operations and it is reasonable to assume that technology for development operations will be available at the appropriate time. Further safeguards exist after the lease sale in that there is a separate approval process for both the exploratory and the development phase. I believe this is the best approach to speeding OCS development while maintaining the necessary safeguards since availability of lease acreage should provide the greatest incentive for rapid development of the needed technology."

The schedule proposes the following timing of sales:

1979:--No. 49 Mid-Atlantic, February; No. 48 Southern California, June; No. 58 Gulf of Mexico, July; No. 54 South Atlantic-Blake Plateau, November; Federal-State Beaufort Sea, December.

1980:--No. 55 N.E. Gulf of Alaska, June; No. 62 Gulf of Mexico, August; No. 46 Kodiak, October; No. 52 North Atlantic, November.

1981:--No. 53 Central-N. California, February; No. 60 Cook Inlet, March; No. 56 South Altantic, April; No. 59 Mid-Atlantic, August; No. 66 Gulf of Mexico, September; No. 57 Bering-Norton, December.

Secretary Andrus emphasized that the sale schedule will assist public and industry planning and preparations for OCS leasing but decisions on whether to proceed with specific sales will be made by him only after all applicable legal requirements have been made and he has studied the comments of the coastal Governors and others on the full range of issues related to the sale.

A schedule with the timing of all of the pre-sale steps and including the schedule for sales in 1977 and 1978 is attached. The 1977-78 section includes some minor revisions, providing for a 60-day period for State review of sale notices, of the schedule announced in May. When the Amendments to the OCS Lands Act are enacted, the schedule will need to be reviewed in accordance with the requirements of Section 18 of that bill.

DECISION PROCESS: OCS LEASE SALES

In arriving at a decision whether to hold a gas and oil lease sale on the Outer Continental Shelf, the Interior Department follows a sequential step by step procedure that includes the following:

I. Call for Nominations and Comments

--Requested from industry, the affected coastal States and units of local government, and the general public.

--Designed to provide a basis for determining the actual area to be investigated for a proposed future lease sale.

II. Tract Selection

--Defines the actual area to be studied and upon which a draft Environmental Impact Statement (EIS) will be prepared.

III. Draft Environmental Impact Statement

--Impacts are examined and alternative actions are evaluated.

--Basic data are collected and examined, including geology, climate, oceanography, biological environment, and natural phenomena unique to the specific area proposed for the sale.

--Specific data collected include information on currents, tides, air and water quality, seasonal temperatures and winds, marine communities of plants and animals, wildlife of any land mass in the area, socio-economics of coastal land areas, commercial and sport fishing, shipping, navigation, military, and beach.

--The risks of oil spills are also weighed on a computerized projection of worst-case analyses.

--Is submitted to the President's Council on Environmental Quality (CEQ) and is available to the public.

IV. Public Hearing

--Gives all interested parties an opportunity to air and record their views concerning the draft EIS and the proposed sale.

V. Final Environmental Impact Statement

--Reflects the information, views, and testimony provided at the public hearing and/or submitted to Interior during the review period for the draft EIS.

--Provides any additional data that may have come to light.

--Is submitted to the President's Council on Environmental Quality (CEQ) for review and is available to the public.

VI. Decision Whether to Hold a Sale

--May result in holding the sale, cancellation of the sale, delay of the sale or modification of the sale by deleting any number of tracts, or by including specific environmental and economic conditions on any or all tracts.

VII. Sale

--If sale decision is affirmative, an official notice is published in the Federal Register at least 30 days prior to sale date.

In most leased areas, it may take more than two years from the date of the sale until production commences; in other areas the time lapse will be five years or even longer. Each lease is monitored throughout its producing life to help assure environmental safety.

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*U.S. GOVERNMENT PRINTING OFFICE : 1977 0-248-227/6615